NORTH CAROLINA
DIVISION OF AIR QUALITY
Application Review

Issue Date: xx

Region: Asheville Regional Office
County: Rutherford
NC Facility ID: 8100028
Inspector's Name: Mike Parkin
Date of Last Inspection: 05/15/2018
Compliance Code: 3 / Compliance - inspection

Facility Data

Applicant (Facility's Name): Duke Energy Carolinas, LLC - Cliffside Steam Station

Facility Address:
Duke Energy Carolinas, LLC - Cliffside Steam Station
573 Duke Power Road
Mooresboro, NC 28114

SIC: 4911 / Electric Services
NAICS: 221112 / Fossil Fuel Electric Power Generation

Facility Classification: Before: Title V **After:** Title V
Fee Classification: Before: Title V **After:** Title V

Permit Applicability (this application only)

SIP: 15A NCAC 02Q .0513
NSPS: N/A
NESHAP: 40 CFR 63, Subpart DDDDD
PSD: N/A
PSD Avoidance: N/A
NC Toxics: N/A
112(r): N/A
Other: 40 CFR 97 Subparts AAAAA, BBBBB, and CCCCC

Contact Data

Facility Contact	Authorized Contact	Technical Contact
Steve Hodges Environmental Coordinator (828) 657-2339 573 Duke Power Road Mooresboro, NC 28114	David Barnhardt Manager (828) 657-2001 573 Duke Power Rd Mooresboro, NC 28114	Daniel Markley Lead Environmental Specialist (704) 382-0696 526 South Church Street Charlotte, NC 28202

Application Data

Application Number: 8100028.14B
Date Received: 08/18/2014
Application Type: Renewal
Application Schedule: TV-Renewal

Existing Permit Data

Existing Permit Number: 04044/T42
Existing Permit Issue Date: 10/13/2017
Existing Permit Expiration Date: 06/30/2022

Total Actual emissions in TONS/YEAR:

CY	SO2	NOX	VOC	CO	PM10	Total HAP	Largest HAP
2016	585.91	1172.36	14.16	612.32	162.69	13.48	8.80 [Hydrogen chloride (hydrochlori]
2015	617.26	1176.38	12.90	541.01	178.96	16.29	9.99 [Hydrogen chloride (hydrochlori]
2014	1253.94	2106.74	19.19	1149.66	269.79	19.63	14.65 [Hydrogen chloride (hydrochlori]
2013	872.92	1611.86	18.38	1173.09	254.08	21.60	16.33 [Hydrogen chloride (hydrochlori]
2012	316.21	458.51	15.51	309.05	203.55	18.67	14.81 [Hydrogen chloride (hydrochlori]

Review Engineer: Rahul Thaker **Review Engineer's Signature:** **Date:** November 19, 2018	**Comments / Recommendations:** **Issue** 04044/T43 **Permit Issue Date:** xx **Permit Expiration Date:** xx

1.0 Purpose of Application

Duke Energy Carolinas, LLC, Cliffside Steam Station, hereinafter "DEC", submitted a Title V application (8100028.14B) to renew its then-existing Title V permit 04044T39. This application also includes a request to renew the Acid Rain permit-portion of the Title V permit.

Separately, DEC submitted three additional applications (8100028.16A, 8100028.17C, and 8100028.18A).

All above applications will be processed in a single permit revision, by renewing and modifying the existing Title V permit (04044T42), as discussed in this application review.

2.0 Facility Description

DEC owns and operates the Cliffside Steam Station (also known as, Rogers Energy Complex), located on the Rutherford-Cleveland County border in North Carolina. The Cliffside Station comprises of coal/No. 2 fuel oil/natural gas-fired electric utility steam generating units (EGUs) [Units 5 and 6], auxiliary boilers, emergency generators/fire pumps, cooling tower, and coal, fly ash, limestone and gypsum storage and handling equipment, in addition to a myriad of insignificant activities of different industrial category types.

Unit 5 is equipped with pollution control equipment consisting of a selective catalytic reduction (SCR) system, a flue gas ash conditioning system, a portable hydrated lime dry sorbent injection system, electrostatic precipitators (ESPs), and a flue gas desulfurization system (FGD. Unit 6 pollution control devices include an SCR, spray dryer absorbers, baghouses, and a FGD system.

The facility's primary business activity is classified under the Standard Industrial Classification code 4911 "Electric Services "[1]. Under North American Industrial Classification System (NAICS), it is classified under code 221112 "Fossil Fuel Electric Power Generation".

3.0 Statement of Compliance

The facility has certified compliance with all applicable requirements through the submittal of E5 forms for each of the applications processed in this permit revision. In addition, based upon the most recent inspection, conducted by the ARO (Mike Parkin) on May 15, 2108, the facility was observed to be "in compliance with Air Permit No. 04044T42…based on the site visit and file review." The same inspection report adds that "over the past five years Duke Energy has not been cited for any violation by the Division of Air Quality".

4.0 Permitting History Since Last Title V Permit Renewal

June 30, 2010	Renewed air quality permit 04044T31 was issued.
February 21, 2011	Air permit 04044T32 was issued per significant modification provision for including a case-by-case 112(j) MACT for boilers ID Nos. ES-6(AuxB) and ES-7(Aux). The permit provided public participation, and EPA and affected states review.
January 20, 2012	Air permit 04044T33 was issued as a 1st step of two-step process in 02Q .0501(c)(2). This permit for the affected coal handling equipment updated the NSPS Subpart Y stipulation. The permit also conformed the changes to NSPS Subpart Db requirements for boiler ES-

[1] Includes establishments engaged in generation, transmission and/or distribution of electric energy for sale.

	Aux6 for visible emissions. Finally, it revised the coal monitoring test methods listed in the permit for Unit 6 HAP compliance.
June 22, 2012	Air permit 04044T34 was issued under the "Reopener for Cause" provision to remove the vacated Clean Air Mercury Rule (CAMR) requirements and modify the existing state-only mercury control requirements in 02D .2500. The permit provided public participation, and EPA and affected states review.
October 25, 2012	Air permit 04044T35 was issued per minor modification provision to revise the HP ratings for the emergency generator (ES-EG6), emergency firewater pump (ES-FWP) and FGD emergency quench pump (QP5) and remove the permit operating restriction of no more than one hour per 24-hour (daily block) period for ES-EG6 and ES-FWP in the applicable stipulation.
December 19, 2012	Air permit 04044T36 was issued as a 1st step of 02Q .0501(c)(2) process including the MACT Subpart DDDDD requirements for Unit 6 auxiliary boiler (ID No. ES-Aux6).
February 1, 2013	Air permit 04044T37 was issued as a 1st step of 02Q .0501(c)(2) process, revising the Unit 6 NSPS monitoring requirement by incorporating the current Subpart Da language.
October 14, 2013	Air permit 04044T38 was issued as a significant modification, incorporating all Unit 6 equipment and Unit 5 FGD project equipment into the Part I of the Title permit in accordance with the Title V process (the Unit 6 and Unit 5 FGD equipment were previously permitted through Part II of the permit). The permit also re-permitted boiler ES-Aux6 through 2nd step of 501(c)(2) process. The other changes included removal of retired Units 1 through 4, addition of compliance assurance monitoring (CAM) plan for Unit 6, addition of Acid Rain program requirements for Unit 6 and renewal of Acid Rain permit requirements for Unit 5, and removal of submittal of Clean Air Interstate Rule (CAIR) permit application, etc.
May 9, 2014	Air permit 04044T39 was issued as a 1st step of 2-step process in 02Q .0501(c)(2) for sources C-21, ES-C20 and ES-C31.
July 20, 2017	Air permit 04044T40 was issued per 02Q .0501(d)(1) provision for use of an optional PM Continuous Emission Monitoring System (CEMS) to the current method of using a Continuous Opacity Monitoring System (COMS) for Unit 5 for complying with 02D .0521 (opacity), 02D .0536 (particulate and annual average opacity), and 02D .0606. The permit also included the substantive requirements of the MACT as promulgated in the most current version of 40 CFR Part 63 Subpart UUUUU.
September 21, 2017	Air 04044T41 was issued as a 1st step of 2-step process in 02Q .0501(c)(2), providing natural gas firing capability to the permitted coal/No. 2 fuel oil-fired EGUs (ES-5 and ES-6).
October 13, 2017	Air 04044T42 was issued pursuant to minor modification provision in 02Q .0515, for installing additional dry ash handling equipment to augment the existing ash handling capability for Unit 5 boiler as follows: (i) Two new 90-inch diameter filter/separators to remove the ash particles from the conveying air stream on the A and B vacuum systems, (ii) One new Unit 5 remote ash storage silo, (iii) One new bin vent filter on the new Unit 5 storage silo, and (iv) A new asphalt paved road to access the remote silo (truck traffic).

5.0 Application Chronology

August 18, 2014	Received the Title V renewal application (8100028.14B) to renew the then-existing permit 04044T39.

June 26, 2015	Received a request to revise the current multi-state averaging plan to a single state (NC) averaging plan for NOx emissions under Acid Rain permit for Unit 5. It was assigned an application number 8100028.15C, but, later, it was consolidated into the renewal application.
June 24, 2016	Received the 2nd step of 501(c)(2) application (8100028.16A) for previously permitted sources (C-21, ES-C20 and ES-C31) through air quality permit 04044T39.
August 16, 2016	Met with the applicant (Cynthia W and Erin W) to discuss the acid rain renewal/modification application. Clarifications on the same day received from applicant (via email) on requested information.
August 23, 2016	DAQ responded on some outstanding issues included in the renewal application via email (Dan Markley).
September 21, 2016	Received an updated insignificant activity list, modifying the insignificant activity list attached to the cover letter of air permit.
October 31, 2016	DAQ raised some additional questions on existing permit requirements on visible emissions monitoring, PM CEMS, diesel fired emergency engines/pumps, and notifications of NSPS construction dates.
December 29, 2016	Received the requested information on issues raised in October 31, 2016 email.
January 3, 2017	Received information on submitted reports under the PSD avoidance stipulation for Unit 5 FGD project.
January 5, 2017	Received information on completion of required testing under NSPS OOO.
January 11, 2017	Received information on NSPS testing for sources LS-11, LS-12, LS13-1 and LS13-2.
January 23, 2017	Received email notification from the applicant to continue keeping the COMS requirement for EGUs as an option to PM CEMS requirement in the permit.
September 13, 2017	Received a request to add three new insignificant activities (emergency engines for water redirect project: two 425 HP and one 600 HP).
December 12, 2017	Received a 502(b)(10) change application (8100028.17C) for use of biodiesel in combustion sources.
December 15, 2017	DAQ sent a 502(b)(10) change acknowledgement letter to the applicant.
February 22, 2018	DAQ sent an email to the applicant responding to their request for an optional use of SCR system when only natural gas is burned in Unit 6 boiler.
July 18, 2018	Received the significant modification application (8100028.18A), requesting regulatory applicability for 5D NESHAP for auxiliary boilers for Units 5 and 6.
August 13, 2018	Received information on CAM applicability for previously permitted control devices: CD-U5SorbBf, CD-U5(DSI), CD-13A, CD-13B, and CD-SiloU5.
August 22, 2018	Received application forms for the submitted 502(b)(10) change for use of biodiesel in combustion sources.
August 28, 2018	Applicant narrowed the request for use of biodiesel for sources ES-12(EmGen), ES-EG6, and ES-FWP only.

October 11, 2018	Received a request to remove coal sampling and reporting requirement in state-only requirement for HCl emissions for Unit 6 under Section 2.1.A.7.
October 11, 2018	Received a request to list a 55-kW propane-fired emergency generator as an insignificant activity. DEC requested also to not list the emergency engines (two 425 HP and one 600 HP) for water redirect project as insignificant activities, as they were not needed for the facility. These engines were initially requested by the Permittee to be insignificant activities on September 13, 2017.

6.0 Regulatory Overview

As per the current air quality permit, emissions sources at DEC's Cliffside Steam Station are subject to the following requirements, in addition to the requirements in the General Conditions:

- 15A NCAC 02D .0501(c) "Compliance with National Ambient Air Quality Standards"
- 15A NCAC 02D .0503 "Particulates from Fuel Burning Indirect Heat Exchangers"
- 15A NCAC 02D .0510 "Particulates from Sand, Gravel, or Crushed Stone Operations"
- 15A NCAC 02D .0515 "Particulates from Miscellaneous Industrial Processes"
- 15A NCAC 02D .0516 "Sulfur Dioxide from Combustion Sources"
- 15A NCAC 02D .0519 "Control of Nitrogen Dioxide and Nitrogen Oxides Emissions"
- 15A NCAC 02D .0521 "Control of Visible Emissions"
- 15A NCAC 02D .0524 "New Source Performance Standards" (40 CFR Part 60, Subparts Da, Db, Y, OOO, and IIII)
- 15A NCAC 02D .0530 "Prevention of Significant Deterioration"
- 15A NCAC 02D .0535 "Excess Emissions Reporting and Malfunctions"
- 15A NCAC 02D .0536 "Particulate Emissions from Electric Utility Boilers"
- 15A NCAC 02D .0540 "Particulates from Fugitive Dust Emission"
- 15A NCAC 02D .0606 "Sources Covered by Appendix P of 40 CFR Part 51"
- 15A NCAC 02D .0614 "Compliance Assurance Monitoring"
- 15A NCAC 02D .1100 "Control of Toxic Air Pollutants"
- 15A NCAC 02D .1109 "112(j) Case-by-Case Maximum Achievable Control Technology"
- 15A NCAC 02D .1111 "Maximum Achievable Control Technology" (40 CFR Part 63, Subparts ZZZZ and UUUUU)
- 15A NCAC 02D .2403 "Nitrogen Oxide Emissions"
- 15A NCAC 02D .2404 "Sulfur Dioxide"
- 15A NCAC 02D .2405 "Nitrogen Oxide Emissions During Ozone Season"
- 15A NCAC 02Q .0309 "Termination, Modification and Revocation of Permits"
- 15A NCAC 02Q .0317 "Avoidance Conditions" (PSD Avoidance)
- 15A NCAC 02Q .0400 "Acid Rain Procedures"
- Avoidance of Major Stationary Source Requirement Under §112
- Senate Bill S1587

All above requirements and the associated permit stipulations are still applicable to the facility sources, except the requirements in 02D .2403 through 02D .2405 and .2500, meeting the requirements in both 15A NCAC 02Q .0500 and 40 CFR 70. A detailed regulatory review of the applicable requirements will not be included in this document, although, a brief explanation for each applicable requirement is included below for ease of understanding. Finally, any new applicable requirement (which is currently not included in the permit) will be discussed in detail.

15A NCAC 02D .0501(c) "Compliance with National Ambient Air Quality Standards"

This rule requires facilities to comply with the ambient air quality standards (State ambient air quality standards (SAAQS), National air quality ambient standards (NAAQS)), listed in 02D .0400. If more stringent controls than the applicable standards in 02D .0500 are required to prevent a violation of ambient air quality standards, the permit shall include a condition requiring such controls.

The DAQ had established a more stringent emission standard of 1.6 lb/million Btu for SO_2 for Unit 5 boiler than the otherwise applicable standard of 2.3 lb/million Btu (02D .0516), to comply with the 3-hour, 24-hour, and annual ambient air quality standards, through an air permit (04044T25), issued on December 15, 2006. The permit stipulation included in Section 2.1 A.1. will be clarified to state that this standard protects the ambient SO_2 standards for 3-hour, 24-hour, and annual averaging standard.

With respect to 1-hour SO_2 ambient standard (75 ppb), promulgated in 75 FR 35520 (June 22, 2010), it needs to be emphasized that this boiler is currently subject to a more stringent emission limit of 0.20 lb/million Btu under the Mercury and Air Toxics Standards (MATS) (Section 2.2.B.2.b. of current permit). The actual SO_2 emission rate for the 1st quarter of 2018 was 0.067116 lb/million Btu[2], much lower than the MATS limit. In addition, for the above NAAQS (or SAAQS), Rutherford County airshed, where this source is located, has been designated "attainment/unclassifiable" by EPA, effective April 9, 2018, as per "NORTH CAROLINA—2010 SULFUR DIOXIDE NAAQS (PRIMARY)", in §81.334. Therefore, the DAQ believes that it is not justified nor required to establish an independent emission standard under 02D .0501(c) to assure compliance with the 1-hour SO_2 ambient standard.

15A NCAC 02D .0510 "Particulates from Sand, Gravel, or Crushed Stone Operations"

Limestone unloading, conveying, and crushing equipment are subject to this requirement. Specifically, the Permittee is required to take measures to reduce particulate matter emissions from becoming airborne to prevent exceedance of ambient standards beyond the property boundary. Moreover, fugitive non-process dust emissions are to be controlled in accordance with 02D .0540. Finally, process-generated dust is to be controlled from crushers with wet suppression, conveyors, screens, and transfer points to prevent exceedance of opacity standards.

The recent inspection report[3] indicates compliance with this requirement. Continued compliance will be determined during subsequent inspections in the future.

15A NCAC 02D .0515 "Particulates from Miscellaneous Industrial Processes"

Flyash transfer and storage systems, limestone storage silo, flyash vacuum systems, Unit 5 remote ash storage silo, coal unloading, conveying, and crushing equipment (Units 5 and 6), and multi-cell cooling tower are subject to this requirement. Allowable PM emission limit is set as per the following:

$E = 4.10 \times P^{0.67}$ for $P \leq 30$ tons/hr, or
$E = 55.0 \times P^{0.11} - 40$ for $P > 30$ tons/hr

Where:
E = allowable emission rate in pounds per hour
P = process weight rate in tons per hour

The recent inspection report[4] indicates compliance with this requirement. Continued compliance will be determined during subsequent inspections in future.

15A NCAC 02D .0516 "Sulfur Dioxide from Combustion Sources"

Auxiliary boilers for Units 5 and 6, and emergency/blackout protection diesel generator are subject to this requirement. The Permittee is required to comply with an applicable SO_2 standard of 2.3 lb/million Btu. The air permit also inadvertently subjected emergency generator and emergency firewater pump to this requirement, which will be corrected.

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[2] Page 46 of May 15, 2018 inspection report.
[3] Page 39 of Id. at 2.
[4] Page 39 of Id. at 2.

Due to low sulfur fuel content in these combustion sources (0.05%w sulfur or 15 ppm sulfur, as applicable), compliance with this standard is expected. The current air permit does not require any monitoring including recordkeeping or reporting for SO_2. As stated above, the potential SO_2 emissions are expected to be much lower than the above allowable standard of 2.3 lb/million Btu. Therefore, the DAQ believes that no monitoring / recordkeeping/ reporting is justified for SO_2 emissions from these sources. No change to the permit stipulation will be made.

15A NCAC 02D .0521 "Control of Visible Emissions"

Auxiliary boilers for Units 5 and 6, emergency/blackout protection diesel generator, emergency quench water pump, emergency firewater pump, emergency generator, emergency firewater pump, and many sources associated with flyash, coal, limestone, and gypsum handling are subject to this requirement.

If the source is manufactured as of July 1, 1971, the emission limit of 40 percent opacity applies, otherwise the source is subject to 20 percent opacity limit.

The permit stipulations included in the current permit for the sources above accurately include the regulatory requirement. If the "normal" level is established for any permit stipulation for visible emissions, the stipulation will be accordingly revised.

The recent inspection report[5] indicates compliance with this requirement. Continued compliance will be determined during subsequent inspections in future.

15A NCAC 02D .0524 "New Source Performance Standards" (40 CFR Part 60, Subparts Da, Db, Y, OOO, and IIII)

NSPS Subpart Da Standards of Performance for Electric Utility Steam Generating Units

This NSPS applies to each electric utility steam generating unit (EUSGU) burning fossil fuel with a heat input capacity of more than 250 million Btu/hr, that is constructed, modified, or reconstructed after September 18, 1978.

The Unit 6 boiler is subject to this NSPS with the following standards:

POLLUTANT	EMISSION LIMIT
Particulate Matter	0.015 lb/million Btu heat input (filterable only) (24-hour daily (block) average) 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity
Sulfur Dioxide	1.4 lb/MWh gross energy output (30-day rolling average), or 95% reduction (30-day rolling average)
Nitrogen Oxides (Expressed as NO_2)	1.0 lb/MWh gross energy output (30-day rolling average)

Particulate matter, opacity, sulfur dioxide, and nitrogen oxides standards apply at all times except during periods of startup, shutdown, or malfunction.

During the 1st quarter of 2018, actual emissions rates were observed to be 0.002396 lb/million Btu (24-hour daily average), 0.343 lb/MWh (30-day rolling average), and 0.454 lb/MWh (30-day rolling average) for PM (filtrable only), SO_2, and NOx, respectively. It should be noted that as per the optional PM CEMS approach in lieu of COMS, allowed in the current air permit, the facility has notified the DAQ that effective January 1, 2018, it plans to monitor PM emissions from Unit 6 using CEMS. Thus, visible emissions monitoring is not required as per the permit.

Compliance is indicated. Continued compliance will be determined during DAQ inspections in future.

NSPS Subpart Db Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

[5] Pages 24 and 39 of Id. at 2.

This NSPS applies to each steam generating unit with a heat input capacity of more than 100 million Btu/hr, that is constructed, modified, or reconstructed after June 19, 1984.

The Unit 6 auxiliary boiler is subject to this NSPS and the following standards apply:

- Sulfur Dioxide – Units firing only oil that contains no more than 0.30 weight percent sulfur are exempt from all other sulfur dioxide emission limits.

- Particulate Matter – Units firing only oil that contains no more than 0.30 weight percent sulfur are not subject to the PM limits.

  Visible emissions from this source shall not be more than 20 percent opacity (except during startup, shutdowns, and malfunctions) when averaged over a six-minute period, except for one six-minute period per hour of not more than 27 percent opacity.

- Nitrogen Oxides – The boiler is not subject to the nitrogen oxides emission limits as long as the nitrogen content of any fuel does not exceed 0.30 weight percent and annual capacity factor does not exceed 10 percent).

Compliance with the visible emissions limit is indicated as per the recent inspection.[6] For relatively clean fuel (0.05 weight sulfur), compliance with sulfur and nitrogen limits is expected. Continued compliance will be determined during subsequent inspections in future.

NSPS Subpart Y Standards of Performance for Coal Preparation and Processing Plants

The provisions of this Subpart apply to affected facilities that commence construction, reconstruction or modification after October 27, 1974, in coal preparation and processing plants that process more than 181 megagrams (Mg) (200 tons) of coal per day.

Coal unloading, conveyance, storage, and crushing operations for both Units 5 and 6 are subject to this NSPS and the following emissions standards apply:

- Particulate emissions from the mechanical vents shall not exceed 0.010 gr/dscf. Visible emissions from coal storage system or coal transfer and loading system, excluding mechanical vents, shall be less than 10 percent opacity.

Compliance with the visible emissions and PM limit is indicated through March 1987 and March 2018 stack testing events as per the recent inspection[7]. Continued compliance will be determined during subsequent inspections in future.

NSPS Subpart OOO Standards of Performance for Nonmetallic Mineral Processing Plants

Limestone unloading, conveying, storage and crushing equipment are subject to this NSPS and the following standards apply:

- Stack emissions of particulate matter from affected facility shall not exceed 0.05 g/dscm (0.022 gr/dscf) and 7 percent opacity.

- Fugitive emissions from affected facility shall not be more than 10 percent opacity.

- Fugitive emissions from enclosed affected facility shall not be more than 10 percent opacity or 15 percent opacity, as applicable.

  OR

[6] Page 39 of Id. at 2.
[7] Page 44 and 45 of Id. at 2.

- The building enclosing the affected facilities shall comply with the following emission limits:
  Fugitive emissions from any building enclosing any transfer point on a conveyor belt or any other affected facility, except emissions from a vent as defined in §60.671, shall not exceed 7 percent opacity. Affected buildings include limestone unloading structure, reagent preparation building for two ball mills, and underground tunnel for two reclaim hoppers and two reclaim feeders.

  Any vent (as defined in §60.671) of any building enclosing any transfer point on a conveyor belt or any other affected facility shall not discharge stack emissions of particulate matter greater than 0.05 g/dscm (0.022 gr/dscf) and 7 percent opacity. Affected buildings include limestone unloading structure, transfer house for conveyor LS-2, and reagent preparation building for two ball mills, and underground tunnel for two reclaim hoppers and two reclaim feeders.

Compliance with the PM standard through periodic monitoring (bagfilter inspection and maintenance) and the visible emissions limits through periodic visible emissions monitoring have been indicated as per the recent inspection.[8] Continued compliance will be determined during subsequent inspections in future.

NSPS Subpart IIII Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

The provisions of this NSPS apply to owners or operators of stationary compression ignition (CI) internal combustion engine (ICE) that commence construction after July 11, 2005, if the engine is manufactured after April 1, 2006 for non-fire pump engine, or if the National Fire Protection Association certified fire pump engine is manufactured after July 1, 2006. The NSPS also applies to each CI ICE if it is modified or reconstructed after July 11, 2005.

An emergency quench water pump, two emergency fire water pumps, and an emergency generator, located at this facility are subject to this NSPS. The following standards apply.

AFFECTED FACILITY (SOURCE)	**AIR POLLUTANT EMISSION LIMIT, g/kW-hr (g/hp-hr)**		
	NOx + VOCs (combined)	**CO**	**PM**
Emergency Quench Water Pump (ID No. QP5)	4.0 (3.0)	3.5 (2.6)	0.20 (0.15)
Emergency Firewater Pump (ID No. FWP5)	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
Emergency Generator (ID No. ES-EG6)	6.4 (4.8)	3.5 (2.6)	0.20 (0.15)
Emergency Firewater Pump (ID No. ES-FWP)			
Model years 2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
Model years 2009 and later	4.0 (3.0)	3.5 (2.6)	0.20 (0.15)

The Permittee shall use diesel fuel in the CI engine, meeting the following requirements, if the displacement of engine is less than 30 liters per cylinder, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.

Sulfur content: Maximum 15 ppm
Cetane index: Minimum 40
or
Aromatic content: Maximum 35 volume percent

[8] Page 39 of Id. at 2.

The current permit includes all applicable provisions. However, for streamlining, the NSPS requirements for these engines and fire pumps will be included in a multiple sources' regulatory portion of the permit (Section 2.2) to avoid repetition of the same requirement for each affected engine in their respective sections of the permit.

The Permittee is required to purchase the certified engines to meet the above standards. Compliance is expected.

15A NCAC 02D .0530 "Prevention of Significant Deterioration"

Unit 6 is subject to PSD (Prevention of Significant Deterioration) requirements for various pollutants (PM_{10}, CO, VOCs, sulfuric acid mist, and lead) when burning coal. Units 5 and 6 are also subject to PSD for CO and VOCs only when burning natural gas or when co-firing natural gas with coal. The following BACTs (Best Available Control Technology) apply:

Unit 6
Coal Only

POLLUTANT	BACT EMISSION LIMIT	CONTROL TECHNOLOGY
PM_{10}	0.012 lb/million Btu heat input (filterable only) 0.018 lb/million Btu heat input (filterable + condensable) Compliance with the PM_{10} emission limits shall be based on a calendar day averaging time except that compliance will be determined over a shorter time period (no less than 6 hours) if the source elects to run the reference test method for less than 24 hours. 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity	Spray dry absorber followed by fabric filter baghouse
Carbon Monoxide	0.120 lb/million Btu heat input Compliance with the carbon monoxide emission limit shall be based the reference test method (minimum 6 hours).	Good combustion control
VOCs	0.003 lb/million Btu heat input Compliance with the VOC emission limit shall be based the reference test method (minimum 6 hours).	Good combustion control
Sulfuric Acid Mist	0.005 lb/million Btu heat input Compliance with the sulfuric acid mist emission limit shall be based the reference test method (minimum 6 hours).	Spray dry absorber followed by fabric filter baghouse
Lead	0.000022 lb/million Btu heat input Compliance with the lead emission limit shall be based the reference test method (minimum 6 hours).	Fabric filter baghouse

Particulate matter, opacity, nitrogen oxides and mercury standards apply at all times except during periods of startup.

Units 5 and 6
Natural Gas only or Natural Gas with Coal

EMISSION SOURCE	POLLUTANT	BACT	CONTROL DESCRIPTION
		Natural Gas Only or Natural Gas and Coal Co-firing	
Unit 5 (ID No. ES-5)	CO	0.08 lb/million Btu (6-hour average), all operations except start-ups and shut-downs	Good combustion control
Unit 6 (ID No. ES-6)	CO	0.12 lb/million Btu (6-hour average), all operations except start-ups and shut-downs	Good combustion control

EMISSION SOURCE	POLLUTANT	BACT Natural Gas Only or Natural Gas and Coal Co-firing	CONTROL DESCRIPTION
Units 5 and 6 (ID Nos. ES-5 and ES-6)	CO	Work practice standards during start-ups and shutdowns – as per MATS requirements	Work practices
Unit 5 (ID No. ES-5)	VOC	0.0055 lb/million Btu (6-hour average), all operations except start-ups and shut-downs	Good combustion control
Unit 6 (ID No. ES-6)	VOC	Natural Gas Only 0.0055 lb/million Btu (6-hour average), all operations except start-ups and shut-downs Natural Gas and Coal Co-firing $E_{gc} = (E_g * Q_g + E_c * Q_c)/Q_t$ (6-hour average), all operations except start-ups and shut-downs Where: E_{gc} = BACT for natural gas and coal co-firing, lb/million Btu E_g = 0.0055 lb/million Btu E_c = 0.003 lb/million Btu Q_g = natural gas heat input in million Btu Q_c = coal heat input in million Btu $Q_t = Q_g + Q_c$	Good combustion control
Units 5 and 6 (ID Nos. ES-5 and ES-6)	VOC	Work practice standards during start-ups and shutdowns – as per MATS requirements	Work practices

The Permittee has demonstrated compliance with the BACT when burning coal for these pollutants as per the recent inspection.[9] For natural gas and natural gas and coal cofiring scenarios, the Permittee has yet to demonstrate compliance. It should be stated here that the DAQ had issued a permit 04044T41 on September 21, 2017, approving natural gas with or without scenarios for both Units 5 and 6. So, the required performance testing is expected in the future and DAQ will determine compliance at that time.

Auxiliary boiler for Unit 6 is subject to the BACT as follows:

POLLUTANT	BACT EMISSION LIMIT	CONTROL TECHNOLOGY
PM_{10}	0.014 lb/million Btu heat input (filterable only) 0.024 lb/million Btu heat input (filterable + condensable)	Low ash fuel 10% capacity factor
Carbon Monoxide	0.036 lb/million Btu heat input Compliance with the carbon monoxide emission limit shall be based the reference test method (minimum 6 hours).	Good combustion control
VOC's	0.0024 lb/million Btu heat input	Good combustion control

[9] Pages 43 and 44 of Id. at 2.

Compliance with the above BACT is expected as the boiler is a limited use boiler which burns clean fuel (0.05 %w sulfur for fuel oil and 0.001 %w sulfur for propane).

Emergency generator (ES-EG6) and emergency firewater pump (ES-FWP) are subject to the following BACT:

AFFECTED SOURCE	POLLUTANT	BACT** (g/hp-hr)	CONTROL TECHNOLOGY
Emergency Generator (ID No. ES-EG6)	Nitrogen Oxides + VOCs	4.8	Low-NOx engine design 0.05% sulfur fuel oil Good combustion control Max. 100 hr/yr usage
	Carbon Monoxide	0.5	Good combustion control Max. 100 hr/yr usage
	PM_{10}	0.15	0.05% sulfur fuel oil Max. 100 hr/yr usage
Emergency Firewater Pump (ID No. ES-FWP)	Nitrogen Oxides + VOCs*	7.8 (2008 and earlier) 3.0 (2009 and later)	Low-NOx engine design 0.05% sulfur fuel oil Good combustion control Max. 100 hr/yr usage
	Carbon Monoxide	0.5	Good combustion control Max. 100 hr/yr usage
	PM_{10}	0.40 (2008 and earlier) 0.15 (2009 and later)	0.05% sulfur fuel oil Max. 100 hr/yr usage

* These diesel engines are not subject to BACT for NOx. However, for purposes of BACT for VOC, the BACT standard is based on federal model year performance standards for diesel engines which specify a limit based on the combined NO + VOC emissions.

** BACT emission limits shall apply at all times. Excess emissions during startup, shutdown and malfunctions shall be evaluated pursuant to 15A NCAC 02D. 0535.

Compliance with the above BACT is expected as these limits are based on applicable NSPS (Subpart IIII) standards and the sources are burning clean fuels (15 ppm sulfur diesel fuel including biodiesel, 0.05%w sulfur for fuel oil).

Finally, many material handling equipment (coal unloading, conveying, storage, and crushing, gypsum conveying, loading, and storage, Unit 6 coal handling, Unit 6 ash handling, and Unit 6 lime handling, and Unit 6 miscellaneous source for Unit 6 (facility haul roads) are subject to BACT for PM/PM10 emissions, as follows:

EMISSION SOURCE	POLLUTANT	BACT*	CONTROL TECHNOLOGY
One railcar coal unloading station and two unloading hoppers (ID No. C-1)	PM_{10}	10 percent opacity [6-minute average]	Partially covered building and dust suppression (Water or chemical)
Two belt feeders (ID Nos. BF-1 and BF-2)	PM_{10}	10 percent opacity [6-minute average]	Underground
Three coal stockout conveyors (ID Nos. C-2, C-3, and C-4)	PM_{10}	10 percent opacity [6-minute average]	Partial enclosure and dust suppression (Water or chemical)
One circular stacker and boom conveyor (ID No. C-7)	PM_{10}	20 percent opacity [6-minute average]	Dust suppression (Water or chemical)
Coal storage pile fugitives (ID Nos. C-9 and C-10)	PM_{10}	None	Good pile management and dust suppression (Water or chemical)

EMISSION SOURCE	POLLUTANT	BACT*	CONTROL TECHNOLOGY
Coal bulldozing (ID No. C-11)	PM_{10}	None	Dressing of working pile
One coal crusher house (ID No. C-15) and associated dust extraction system (ID No. CD-34)	PM_{10}	10 percent opacity [6-minute average]	Dust extraction system, partial enclosure for conveyor and enclosed building for crusher house
One railcar limestone unloading station (ID No. LS-1)	PM_{10}	20 percent opacity [6-minute average]	Partially covered building and dust suppression (Water or chemical)
Two limestone unloading hoppers (ID No. LS-1A and LS-1B)	PM_{10}	10 percent opacity [6-minute average]	Partially covered building and dust suppression (Water or chemical)
Two belt feeders (ID Nos. BF-3 and BF-4)	PM_{10}	10 percent opacity [6-minute average]	Underground
One limestone stockout conveyor (ID No. LS-6)	PM_{10}	10 percent opacity [6-minute average]	Partial enclosure and dust suppression (water or chemical)
One limestone storage pile (ID No. LS-8)	PM_{10}	None	Good pile management and dust suppression (Water or chemical)
Limestone bulldozing (ID No. LS-9)	PM_{10}	None	Dressing of working pile
Limestone reclaim hoppers (ID Nos.LS-10)	PM_{10}	10 percent opacity [6-minute average]	Underground
Two limestone reclaim feeders (ID Nos. VF-40 and VF-41)	PM_{10}	10 percent opacity [6-minute average]	Underground
One limestone reclaim conveyor (ID No. ES-11)	PM_{10}	10 percent opacity [6-minute average]	Partial enclosure and dust suppression (water or chemical)
One limestone silo fill conveyor (ID No. LS-12) and two limestone silos (ID Nos. LS13-1, and LS13-2)	PM_{10}	0.01 grain/dscf (filterable only) for both PM and PM_{10} [3-hr average], and 7 percent opacity [6-minute average]	Baghouse, partially underground and partial enclosures for conveyors
Two limestone ball mills (ID Nos. LSBM-1 and LSBM-2)	PM_{10}	15 percent opacity [6-minute average]	Total enclosure
Two gypsum stockout conveyors (ID Nos. GS-3 and GS-4)	PM_{10}	20 percent opacity [6-minute average]	None
Gypsum truck loading (ID No. GS-9)	PM_{10}	20 percent opacity [6-minute average]	None
One gypsum storage pile (ID No. GS-5)	PM_{10}	None	Good pile management and dust suppression (Water or chemical)
Landfill for ash and gypsum (ID No. Landfill)	PM_{10}	None	Good pile management and dust suppression (Water or chemical)

EMISSION SOURCE	POLLUTANT	BACT*	CONTROL TECHNOLOGY
Emergency quench water pump (ID No. QP5)	PM_{10}	0.2 gram/kW-hr (filterable only) [3-hr average]	None
U6 Coal Reclaim Hoppers (ID No. ES-C19)	PM_{10}	10 percent opacity [6-minute average]	Underground
Coal Reclaim Feeders for Unit 6 (ID Nos. ES-VF1 thru ES-VF4)	PM_{10}	10 percent opacity [6-minute average]	Underground
Coal Reclaim Conveyor RC11 to U6 Boiler Building (ID No. ES-C27), Coal Reclaim Conveyor RC12 to U6 Boiler Building (ID No. ES-C28), Unit 6 Tripper Conveyor TR2 (ID No. ES-C29), and Unit 6 Tripper Conveyor TR3 (ID No. ES-C30) with associated bagfilter (ID No. CD-28)	PM_{10}	0.01 grain/dscf (filterable only) for both PM and PM_{10} [3-hr average], and 10 percent opacity [6-minute average]	Baghouse, partial enclosures and enclosed buildings
Dry Fly Ash Pickup at Bagfilter (ID No. ES-A9), Dry Fly Ash Silo (ID No. ES-A6), Dry Fly Ash Truck Loading (ID No. ES-A7), and Ash Vacuum Exhauster (ID No. ES-A5)	PM_{10}	0.01 grain/dscf (filterable only) for both PM and PM_{10} [3-hr average], and 20 percent opacity [6-minute average]	Baghouse
Dry Fly Ash discharge to truck (ID No. ES-A12)	PM_{10}	20 percent opacity [6-minute average]	Dust suppression (Water or chemical)
Lime Silo for SDA (ID No. ES-LSSDA)	PM_{10}	0.01 grain/dscf (filterable only) for both PM and PM_{10} [3-hr average], and 20 percent opacity [6-minute average]	Baghouse
Facility haul roads (ID No. FVehicle)	PM_{10}	None	Dust suppression (Water or chemical)

* BACT shall apply at all times. Excess emissions during startup, shutdown and malfunctions shall be evaluated pursuant to 15A NCAC 02D. 0535.

Compliance with the above BACT were demonstrated during the 1st quarter of 2018 as per the recent inspection report.[10]

15A NCAC 02D .0535 "Excess Emissions Reporting and Malfunctions"

Excess emissions during start-up, shut-downs, or malfunctions are governed by the requirements under 02D .0535. However, if the source is subject to 02D .0524 (NSPS), .1110 (Part 61 NESHAPs), or .1111 (Part 63 NESHAPs) then, the source must meet the requirements of those applicable regulations, unless the excess emissions exceed an emission limit established in a permit issued under 15A NCAC 02Q .0700 that is more stringent than the emission limit, established pursuant to any of the above regulations.

[10] Page 39 and 40 of Id. at 2.

Compliance is expected.

15A NCAC 02D .0536 "Particulate Emissions from Electric Utility Boilers"

Unit 5 is subject to the following particulate matter standards as follow:

- As determined by stack test
  0.25 pounds per million Btu heat input

- As determined by PM CEMS
  0.030 pounds per million Btu heat input (or 0.30 pounds per MWh)

- 16 percent annual average opacity State-only Requirement

The Unit 5 was tested on May 16, 2017 and the test results showed an actual PM (filterable only) emission rate of 0.003 lb/million Btu. In addition, during the 1st quarter of 2018, the actual maximum PM emission rate was observed to be only 0.001806 lb/million Btu using CEMS. Finally, the average annual opacity was observed to be only 0.81%. Compliance is indicated. Refer to the recent inspection report.[11]

15A NCAC 02D .0540 "Particulates from Fugitive Dust Emission"

This regulation governs the requirements for control of non-process fugitive dust emissions. The Permittee must not allow non-process fugitive dust emissions to cause or contribute to substantive complaints. The current permit includes all applicable requirements of the regulation. Compliance is expected.

15A NCAC 02D .0606 "Sources Covered by Appendix P of 40 CFR Part 51"

The regulation includes minimum continuous emissions monitoring for NOx and PM, including continuous opacity monitoring requirements for Unit 5 boiler. The current permit includes the applicable provisions for the affected pollutant PM with respect to both CEMS and COMS. The permit defines the percent excess emissions (EE) and monitor downtime for both PM and opacity.

Compliance is expected.

15A NCAC 02D .0614 "Compliance Assurance Monitoring"

During the renewal of a Title V permit, compliance assurance monitoring requirements need to be addressed for a pollutant specific emission unit (PSEU), if the PSEU (i) is subject to any non-exempt emission limitation or standard, (ii) is using a control device, and (iii) its pre-control potential emissions are greater than the major source threshold.

The current permit includes a CAM plan for emissions of PM for Unit 5, controlled by two ESPs. The plan includes opacity as an indicator using the Part 75 certified COMS with the excursion level set at 25 percent. If the five percent of COMS data in a calendar quarter exceeds this level, then the Permittee is required to perform the stack testing in the following quarter. No excursions were reported for Unit 5 as per the recent inspection[12].

It needs to be stated here that the current permit stipulation for Unit 5 CAM plan in Section 2.1 A.8.c. exempts periods of startup, shutdown, off-line activities, malfunctions, and maintenance (soot blowing) activities, from defining excursion at 25 percent opacity (3-hour block average). The CAM regulation does not allow such exemption. See §64.7(c). The CAM only exempts data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities. Thus, this permit stipulation will be corrected per the regulation, as discussed above.

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[11] Pages 30, 43 and 46 of Id. at 2.
[12] Page 31 of Id. at 2.

For Unit 6, the permit includes a CAM plan for two spray dryer absorbers and two bagfilters, controlling emissions of PM_{10} (condensable only)[13] and sulfuric acid mist. The permit includes the following indicators:

1. average flue gas temperature (ºF) at the inlet of each fabric filter and at the flue gas exit from the air preheaters;
2. lime slurry feed rate (gpm) to the in-service Spray Dry Absorber (SDA) Pre-Mix Tank; and
3. status indicators showing SDA atomizers in service, coal feed in service, fabric filter bypass closed, and the active SDA Pre-Mix Tank (Tank A or B).

The indicator ranges are as follows:

1. When the average air preheater temperature (average of both preheaters) is less than or equal to 250 ºF:
   i. fabric filter inlet temperature for each active flue gas duct is less than or equal to 240 ºF (hourly average);
   ii. fabric filter system is in service (bypass closed).

2. When the average air preheater temperature (average of both preheaters) is greater than 250 ºF:
   i. fabric filter inlet temperature for each active flue gas duct is less than or equal to 240 ºF (hourly average);
   ii. fabric filter system is in service (bypass closed);
   iii. one or more SDA atomizers are in service for each active flue gas duct; and
   iv. lime slurry feed rate to active pre-mix tank is 7 gpm or greater (hourly average).

An excursion exists if any of these conditions are not met. Excursions trigger an inspection of the control system and corrective action to be initiated within one hour.

For Unit 6, as per the recent inspection, for the 4th quarter of 2018, a total of five excursion events with a total combined duration of five hours were noted, equaling a 0.27 percent of operating time for the quarter[14].

For operation when only No. 2 fuel oil is being burned in this boiler:

For CAM provision, the permit also states that continuous compliance with the sulfuric acid emissions limit is assured without any operation of a control device for Unit 6 boiler. The sulfur content of the Unit 6 No. 2 fuel oil for startup is limited to 0.05 percent by weight.

The Permittee has also provided CAM applicability for all other sources. As per the submittals, for all other emission sources (other than Units 5 and 6), either the source is not equipped with a control device, or the control device is integral to the source, or the pre-control emissions are less than the major source threshold. Therefore, CAM plan is not required for any other sources.

Finally, all sources equipped with control devices, permitted since the submittal of a renewal application, were also evaluated for CAM requirement. They are:

- ES-U5Sorb1 and ES-U5Sorb2 – Two portable hydrated lime sorbent receiving trailers with bag filter CD-U5SorbBf

  The bagfilters on the portable hydrated lime sorbent trailers are part of an inherent process for receiving and storing hydrated lime (part of a pneumatic transfer and storage system. Therefore, the equipment (bagfilters) are not "control devices", per § 64.1.

- ES-13A and ES-13B – A and B flyash vacuum systems with filter/separators CD-13A and CD-13B

  The bagfilters on the A and B flyash vacuum systems are part of an inherent process for removing ash from the process stream (part of a pneumatic transfer system). Therefore, the equipment (bagfilters) are not "control

[13] CAM was not required for filtrable PM_{10}, because PM CEMS is deemed to a continuous compliance determination method; thus, the PSEU exempt from CAM requirement for filtrable portion.
[14] Page 32 of Id. at 2.

devices", per § 64.1. In addition, these bagfilers discharge into the inlet to the Unit 5 ESPs and as discussed above, the ESPs do have a CAM plan for PM emissions.

- ES-SiloU5 – Unit 5 remote ash silo with bin filter CD-SiloU5

  The bagfilters on the Unit 5 remote ash silo are part of an inherent process for the storage of flyash (part of a pneumatic transfer and storage system).

- CD-U5(DSI) – Portable hydrated lime dry sorbent injection system installed on coal fired boiler ES-59U5Boiler)

  This control device is installed to reduce the emissions of sulfur trioxide, which is not a regulated pollutant under the Title V program, and there are no emission standards applicable to this pollutant. Thus, CAM does not apply.

<u>15A NCAC 02D .1100 "Control of Toxic Air Pollutants"</u>

The current permit includes the following approved air toxics emissions limits:

Emission Source	Toxic Air Pollutant	Emission Limit(s)
Coal Storage and Handling	Arsenic and inorganic arsenic compounds	0.1408 lb/yr
	Beryllium	0.0215 lb/yr
	Cadmium	0.00534 lb/yr
	Soluble Chromate Compounds as Chromium VI Equivalent	0.000082 lb/day
	Manganese and compounds	0.001035 lb/day
	Mercury Vapor	0.000005 lb/day
	Nickel Metal	0.000118 lb/day
Ash Storage and Handling	Arsenic and inorganic arsenic compounds	0.6627 lb/yr
	Beryllium	0.0976 lb/yr
	Cadmium	0.0122 lb/yr
	Soluble Chromate Compounds as Chromium VI Equivalent	0.000422 lb/day
	Manganese and compounds	0.002175 lb/day
	Mercury Vapor	0.000021 lb/day
	Nickel Metal	0.001037 lb/day

Compliance is expected.

<u>15A NCAC 02D .1109 "112(j) Case-by-Case Maximum Achievable Control Technology"</u>

Unit 5 auxiliary boiler is subject to this requirement. The current permit includes boiler inspection and maintenance requirement on an annual basis along with the recordkeeping requirement. This requirement ceases to apply on May 19, 2019 and the boiler becomes subject to the 02D .1111 requirement, as discussed elsewhere (Section 7.3 below) in this application review.

Compliance is expected.

<u>15A NCAC 02D .1111 "Maximum Achievable Control Technology" (40 CFR Part 63, Subparts ZZZZ and UUUUU)</u>

NESHAP Subpart ZZZZ National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

This Subpart establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions.

The status of whether the source is "existing" or "new" is based on the cut-off dates of December 19, 2002 and June 12, 2006, as applicable.

Emergency/blackout protection diesel generator is required to submit initial notification within 120 days of source becoming subject under this NESHAP. The facility had sent the initial notification to the DAQ in 2005, including a statement on source has no additional requirement under the NESHAP and the basis of exclusion. The Permittee is also required to keep records for this applicability determination for five years after the determination. No other requirements under Subparts A and ZZZZ shall apply. The facility has complied with / satisfied all above requirements. The renewed permit will remove this specific MACT ZZZZ stipulation on notification and recordkeeping, as the requirements have been satisfied, as discussed above.

Separately, emergency quench water pump is subject to the NSHAP. The source is required to demonstrate compliance with the NESHAP by complying with the NSPS Subpart IIII requirement. Compliance is indicated as the source does comply with the NSPS Subpart IIII requirements, as discussed earlier in this application review.

Finally, the emergency generator EG6 is subject to the NESHAP with only initial notification requirement, which the DEC has satisfied on May 22, 2012.

NESHAP Subpart UUUUU National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

This subpart applies to each EGU, as defined in the regulation, regardless whether the facility is a major or an area source.

Both Units 5 and 6 are subject to this NESHAP and all applicable requirements have been properly included in the current permit. The following are applicable emission standards for each:

- filterable particulate matter (PM) - 3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh;

  OR

  total non-Hg HAP metals - 5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh;

  OR

  individual HAP metals:

Antimony (Sb)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh
Arsenic (As)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh

Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh
Cadmium (Cd)	3.0E-1 lb/TBtu or 3.0E-3 lb/GWh
Chromium (Cr)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh
Cobalt (Co)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh
Lead (Pb)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh
Manganese (Mn)	4.0E0 lb/TBtu or 5.0E-2 lb/GWh
Nickel (Ni)	3.5E0 lb/TBtu or 4.0E-2 lb/GWh
Selenium (Se)	5.0E0 lb/TBtu or 6.0E-2 lb/GWh

- hydrogen chloride (HCl) - 2.0E-3 lb/MMBtu or 2.0E-2 lb/MWh;

  OR

  sulfur dioxide (SO_2) - 2.0E-1 lb/MMBtu or 1.5E0 lb/MWh

- mercury (Hg) - 1.2E0 lb/TBtu or 1.3E-2 lb/GWh

The Permittee has opted to comply with the filtrable PM limit (instead of total non-Hg HAP metals limit or individual HAP metals limits), SO_2 limit (instead of HCl limit), and Hg limit. As per the 4th quarter 2018 report as discussed in the recent inspection report[15], actual maximum emissions were observed to be as follow:

Unit 5
Filtrable PM - 0.001806 lb/million Btu (using PM CEMS)
SO_2 - 0.067116 lb/million Btu (using SO_2 CEMS)
Hg – 0.004255 lb/GWh (using Hg CEMS)

Unit 6
Filtrable PM - 0.001938 lb/million Btu (using PM CEMS)
SO_2 - 0.042796 lb/million Btu (using SO_2 CEMS)
Hg - 0.001275 lb/GWh (using Hg CEMS)

Compliance is indicated. Continued compliance will be verified through future inspections and records review.

15A NCAC 02D .2403 Nitrogen Oxide Emissions
15A NCAC 02D .2404 Sulfur Dioxide
15A NCAC 02D .2405 Nitrogen Oxide Emissions During Ozone Season

These are Clean Air Interstate Rules (CAIR) requirements for emissions of NOx (annual and ozone season) and SO_2 for existing electric utility steam generating units (such as fossil fuel fired boilers producing electricity for sale and serving an electric generator with nameplate capacity of at least 25 MW), complying with the "good neighbor" provision in §110(a)(2)(D)(i) of the CAA.

The permitted EGUs (both Units 5 and 6) were previously subject to these CAIR requirements. Effective February 1, 2016, these requirements have been repealed, and have been supplanted with the Cross-State Air Pollution Rule (CSAPR) requirements. The background on the CAIR v. CSAPR is described below:

On July 11, 2008, in North Carolina v. EPA, the US Court of Appeals for the D. C. Circuit ("DC Circuit") had found the EPA's CAIR illegal. The Court vacated and remanded this rule. But, on rehearing, on December 23, 2008, the Court remanded without vacatur the CAIR so that the EPA could remedy the rule consistent with the above July 2008 opinion. In brief, the DC Circuit had left the CAIR in place until the replacement of CAIR was promulgated.

On August 8, 2011 (76 FR 48208), the EPA promulgated the CSAPR, replacing the CAIR, again under the good neighbor provision, as cited above. The DC Circuit on December 30, 2011 stayed the CSAPR and asked the EPA to continue implementing the CAIR. Subsequently on merits, on August 21, 2012, the same Court in EME Homer City

[15] Page 46 of Id. at 2.

Generation v. EPA, vacated the entire CSAPR. But, on April 23, 2014, the US Supreme Court in EPA v. EME Homer City Generation, reversed the judgement of the DC Circuit in the CSAPR (that is, upheld the CSAPR) and remanded the case back to the DC Circuit. Then, the DC Circuit on October 23, 2014 issued an Order, lifting the stay of CSAPR. Finally, on December 3, 2014 (79 FR 71663), EPA made changes to its regulations (such as tolling the existing deadlines) consistent with the above Order, requiring to comply with the CSAPR's Phase 1 and 2, starting January 1, 2015, and January 1, 2017, respectively. With respect to "sun-setting" the CAIR requirements, EPA has ruled that it will not be carrying out any functions or enforcing any requirements for any control period after December 31, 2014, for both annual and ozone season NOx, and for annual SO_2, as per §52.35(f) and §52.36(e), respectively.

Unlike the CAIR, the CSAPR is a federal implementation plan (FIP) and is not enforceable by NC. The DAQ will, therefore, include the applicability of the CSAPR in the Title V permit without any detailed requirements, as follows. It needs to be noted that the CSAPR is also referred to as the "Transport Rule (TR)" in EPA's regulations.

> For fossil fuel-fired fired boilers (ID Nos. ES-5 (U5Boiler) and ES-6), the Permittee shall comply with all applicable requirements of 40 CFR Part 97, Subpart AAAAA "TR NOx Annual Trading Program", Subpart BBBBB "TR NOx Ozone Season Trading Program", and Subpart CCCCC "TR SO_2 Group 1 Trading Program".

In summary, through the issuance of a renewed permit, the CAIR requirements will be removed and the above CSAPR requirements will be referenced as a federal-only requirement, without including any substantive details.

<u>15A NCAC 02Q .0309 "Termination, Modification and Revocation of Permits"</u>

The current permit includes a state-only requirement for Unit 6 boiler to limit NOx and SO_2 emissions, when burning coal, to no more than 0.07 lb/million Btu and 0.12 lb/million Btu, respectively, both on a rolling 30-day average.

Based on the recent inspection, maximum NOx and SO_2 emissions were observed to be 0.054 lb/million Btu and 0.042 lb/million Btu, respectively, during the 1st quarter of 2018[16]. Compliance is indicated.

<u>15A NCAC 02Q .0317 "Avoidance Conditions" (Avoidance of PSD)</u>

To avoid major modification of PSD,

- Unit 5 (ID No. ES-5) shall not discharge into the atmosphere more than 2,465 tons per year of nitrogen oxides on a rolling consecutive 12-month period basis.

- Unit 5 and 6 (ID Nos. ES-5 and ES-6) shall not discharge into the atmosphere more than 6,370 tons per year of nitrogen oxides on a rolling consecutive 12-month period basis.

- Units 5 and 6 (ID Nos. ES-5 and ES-6) shall not discharge into the atmosphere more than 25,185 tons per year of sulfur dioxide on a rolling consecutive 12-month period basis.

Based on the recent inspection,

rolling 12-month (April 17 through March 2018) NOx emissions from Unit 5 were 749 tons,
rolling 12-month (April 17 through March 2018) total NOx emissions from both Units 5 and 6 were 1902 tons, and
rolling 12-month (April 17 through March 2018) total SO_2 emissions from both Units 5 and 6 were 1085 tons.[17]

Compliance is indicated. Continued compliance will be determined through future inspections.

<u>15A NCAC 02Q .0400 "Acid Rain Procedures"</u>

[16] Page 30 and 31 of Id. at 2.
[17] Page 31 of Id. at 2.

Units 5 and 6 are subject to requirements for both SO_2 and NOx under the Acid Rain program. Specifically, Unit 5 is allocated SO_2 allowance in accordance with Tables 2, 3 or 4 of 40 CFR 73. Unit 5 is subject to a NOx limit based on an approved multi-state (NC, SC, IN, and KY) averaging plan. Through the renewal of an existing Title V permit including the Acid Rain permit, the Permittee has requested to divorce the Unit 5 from a multi-state plan and establish a new NOx limit through its inclusion in a new NC-based (single state) plan. This NC plan includes all coal-fired EGUs owned by Duke Energy in NC, except Unit 6 at Cliffside, as follows:

Belews Creek Units 1 and 2
Cliffside Unit 5
Allen Units 1 through 5
Marshall Units 1 through 4
Mayo Units 1A and 1B
Roxboro Units 1 and 2, 3A, 3B, 4A, and 4B

The Permittee provided a demonstration on how its intends to establish an averaging plan for its NC-based units through a submittal of an “Acid Rain NOx Averaging Plan.” The plan compares the Btu-weighted annual emission rate averaged over the units if they are operated in accordance with the proposed averaging plan to the Btu-weighted annual average emission rate for the same units operated in in accordance with the applicable limits under §§76.5 through 76.7. The demonstration for any averaging plan must yield an emission rate less than the emission rate based on the applicable limits under the above provisions. Based on the submitted plan and verified by DAQ, the emissions rate for the proposed averaging plan is 0.376 lb/million Btu, less than the emission rate of 0.443 lb/million Btu, if all NC units would have operated under the applicable limits under §§76.5 through 76.7. Compliance is indicated.

With respect Unit 6, which is not part of the above NOx averaging plan, the applicable limit is 0.46 lb/million Btu for wall-fired category under §76.7(a)(2). This unit is not allocated SO_2 allowances as it is considered a “new unit” under the Acid Rain program.

The Acid Rain permit will be renewed for five calendar years and modified based on the above discussions.

Finally, it needs to be emphasized that the Acid Rain program is entirely administered and enforced by the EPA and the DAQ is involved.

Avoidance of Major Stationary Source Requirement Under §112

For Unit 6, the Permittee had taken limits to avoid becoming a major stationary source under §112 at the time of issuance of air quality permit 04044T28 (January 29, 2008), as a state-only requirement.

It needs to be stated here that at the time, the hazardous air pollutants from electric utility steam generating units were regulated under §111 (40 CFR 60, Subpart Da) through the promulgation of CAMR and not under §112. Currently, the HAPs emissions for EGUs are regulated under §112 through promulgation of MATS (40 CR 63, Subpart UUUUU), reversing the previous promulgation under §111.

The permit stipulation includes either quarterly or annual, depending upon the emission rate, stack testing requirements for HCl. If the emission rate of HCl is less than 1.83 lb/hr for consecutive four quarters, the Permittee can perform stack testing on an annual basis. If the emissions of HCl are greater than the above cut-off value for a consecutive two quarters, the Permittee is required to install and operate CEMS for this pollutant.

The permit also includes coal sampling and analysis requirements for each train shipment for chlorine content and higher heating value (HHV). If the annual average value of chlorine exceeds 3209 ppm on a dry basis or the annual average HHV is less than 9376 Btu/lb on an as-received basis, the Permittee is requited to install and operate HCl CEMS.

The Table below shows the actual HCl emission rates since the commencement of operation (May 2012) of Unit 6:

Year	HCl

	Pollutant Emission Rate lb/hr
2018	< 0.18*
2017	< 0.23*
2016	< 0.34*
2015	< 0.18*
2014	< 0.41*
2013	< 0.60*

*All these tests include "non-detects" or results that are less than the detection level for the sample.

The following Table summarizes results for chlorine content and heat content for the coal received for burning in Unit 6 since this boiler commenced operation:

Dates	Chlorine Content Annual Average ppm	HHV Annual Average Btu/lb
April 2012-June 2018	Maximum 2,091.3 (Sept 2016)	Minimum 11,063 (March 2013)
Current (June 2018)	1,310.6	12,039
Permit Limits	Maximum 3,209	Minimum 9,376

With respect to coal sampling, the Permittee has requested to discontinue it, as the historical information to date indicates that the chlorine content is well within the permit value and the HHV for the as-received coal has always been higher than the permit value as above. The Permittee has emphasized that it will continue the stack testing for HCl, however.

Based on the above results of coal received for burning in Unit 6, the DAQ is approving the DEC request to discontinue coal sampling as the actual sampling results showed adequate margin and the stack testing for HCl will continue, to provide direct emission measurements for the intended pollutant.

Senate Bill S1587

Per Part I, Section 5.4 of this Senate Bill, actual SO_2 emissions, when burning coal, from Unit 6 shall not exceed 0.15 lb/million Btu on a 30-day rolling average. As stated previously, actual maximum SO_2 emissions from Unit 6 during the 1st quarter of 2018 were only 0.042 lb/million Btu, indicating compliance. It should be noted that this is a state-only requirement.

7.0 Other Applications Consolidated into Title V Renewal Application

7.1 Application 8100028.16A

The Permittee submitted this application to complete a 2nd step of a two-step process in accordance with 02Q .0501(c)(2) application for the previously permitted sources (ID Nos. C-21, ES-C20 and ES-C31) through an air quality permit 04044T39. These pieces of equipment are to be re-permitted using the significant modification provision of Title V (CAA). They are Unit 6 coal Unit 6 coal blend reclaim hopper (C-20), Unit 6 coal blend reclaim conveyor (C-31), and Unit 5 coal blend reclaim hopper (C-21).

Emissions estimate and a detailed regulatory review for the equipment are included in a permit review, when the sources were initially permitted (04044T39, 5/9/14) as a 1st step of a two-step process in accordance with 02Q .0501(c)(2) process. The Appendix A (Page 31) includes this referenced permit review. Refer to the Appendix for details.

7.2 Application 8100028.17C

The Permittee wishes to burn diesel including biodiesel in the permitted emergency generators (ID Nos. ES-12 and EG6) and fire water pump (ID No. FWP). These sources are currently permitted to burn No. 2 fuel oil. Burning of diesel in the above sources provide additional fuel flexibility. The power output values for each are as follows:

Source ID	Generator or Firewater Pump Power Output HP	Engine Power Output HP
ES-12(EmGen)	1341	1480
ES-EG6	2922	3350
ES-FWP	359	430

The applicant had initially requested to include the Units 5 and 6 boilers (EGUs) and Units 5 and 6 auxiliary boilers as well for diesel burning, which the applicant later rescinded.

It should be noted that biodiesel is a non-distillate fuel, defined as a type of diesel fuel by the EPA per §80.2(x).

The emissions profiles for both diesel fuel and No. 2 fuel oil are expected to be similar (if not the same) as both are part of the same petroleum distillation fraction. Only difference is their usage: No. 2 fuel oil is typically used for space heating, electric power generation, and steam production for commercial, institutional, and industrial sources, while the diesel fuel (such as No. 2 diesel) is typically used in diesel engines, both on- and off-road engines.

The emissions are expected to be lower for the biofuels than for the petroleum distillate fuel.[18] In addition, citing the EPA, NC has described the potential emissions reductions with use of biodiesel (100%, B100), compared to conventional diesel, in the amounts of 50% (CO), 70 % (PM), hydrocarbons (40%), and sulfates (100%), with a slight increase in NOx (9%)[19], and the DAQ had concluded that "when considering the combined benefits of all these reductions, the small increase in nitrogen oxides (NOx) should not overshadow the net environmental gain with biodiesel use in North Carolina. Biodiesel is a viable part of the overall effort to improve our air quality."[20]

The following are emissions estimates for these generators. Each is based upon 500 hours of operation, applicable AP-42 emissions factors (Section 3.2 Natural Gas-fired Reciprocating Engines, 7/00, Section 3.3 Gasoline and Diesel Industrial Engines, 10/96, and Section 3.4 Large Stationary Diesel and All Stationary Dual-Fuel Engines, 10/96), and engine power output as tabled above. The estimated NOx emissions account for increase in emissions of nine percent over diesel fuel, as discussed above.

Pollutant	ES-12(EmGen) Potential Emissions TONS/YR	ES-EG6 Potential Emissions TONS/YR	ES-FWP Potential Emissions TONS/YR
PM	0.26	0.59	0.20
PM-10	0.26	0.59	0.20
PM-2.5	0.26	0.59	0.20
NOx	5.25	11.88	3.03
VOC	0.24	0.59	0.23
CO	2.04	4.61	0.60
SO_2	Negligible	Negligible	Negligible
Single HAP	0.002 (benzene)	0.005 (benzene)	0.000740 (formaldehyde)

[18] Page ii. and 44, "Characterizing Emissions from the Combustion of Biofuels", EPA/600/R-08/069, USEPA, RTP, NC, September 2008, Available at https://nepis.epa.gov/Exe/ZyPDF.cgi/P1009IYE.PDF?Dockey=P1009IYE.PDF.
[19] Division of Air Quality Position on Biodiesel, B. Keith Overcash, (former) Director, November 5, 2004.
[20] Id. at 17.

Pollutant	ES-12(EmGen) Potential Emissions TONS/YR	ES-EG6 Potential Emissions TONS/YR	ES-FWP Potential Emissions TONS/YR
Total HAP	0.005	0.01	0.002410

These sources are subject to the requirements in 02D .0516, 02D .0521, .and .1111 (NESHAP Subpart ZZZZ). In addition, sources EG6 and FWP only are subject to 02D .0524 (NSPS Subpart IIII) and .0530 requirements. Regulatory applicability and compliance status for each of these existing sources have been discussed in Section 6 above. No change in compliance is expected due to use of diesel including biodiesel.

7.3 Application 8100028.18A

This application includes a regulatory applicability review for the permitted Unit 5 auxiliary boiler with respect to NESHAP Subpart DDDDD (National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters). This boiler is currently subject to a case-by-case major source MACT requirements under §112(g) of the CAA, as discussed above in Section 6. The case-by-case requirement will cease to apply to the boiler after May 19, 2019 and the requirements in the Subpart DDDDD apply starting May 20, 2019, as stated above.

It should be noted that no physical or operational change is requested for the boiler.

The boiler qualifies as a limited-use boiler, as defined in §63.7575, as follows:

> *Limited-use boiler or process heater* means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels and has a federally enforceable annual capacity factor of no more than 10 percent.

The renewed permit will include an enforceable requirement to limit the annual capacity factor to less or equal to 10 percent when burning any fuel. The applicant proposes to track the fuel usage for the boiler and maintain calculations of the monthly heat inputs to demonstrate that it is operating at the capacity factor not more than 10 percent on an annual basis.

With respect to an initial notification requirement in §63.7545(a), the Permittee had sent the initial notification on February 25, 2015 to DAQ.

Per §63.7500(a)(3), the boiler must be maintained in a manner consistent with safety and good air pollution control practices for minimizing emissions.

The initial tune-up must be completed prior to the compliance date of May 20, 2019. Limited use boilers must perform tune ups once every five years but no more than 61 months from the previous tune-up. If the boiler is not operating on the required date for a tune-up, the tune-up must be completed within 30 calendar days of start-up. Finally, the burner inspections can be delayed until the next scheduled or rescheduled shutdown, but each burner must be inspected at least once every 72 months. Refer to §§63.7500(c), 63.7515(d), and 63.7540(a)(10), (12) and (13).

The Permittee is required to keep records on maintenance procedures including records showing that these procedures were followed. In addition, records which support that the required tune-ups were completed, need to be kept, as per §63.7540(a)(3). Finally, a copy of federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the limited-use boiler was operating must be kept, per §63.7555(a) and (d)(3).

With respect to reporting requirements, a 5-year compliance report can be submitted to the DAQ instead of a semi-annual report. The first compliance report must cover the period beginning on 5-years after the compliance date and must be postmarked or submitted no later than January 31st. Subsequent compliance reports must cover the applicable 5-year periods from January 1 to December 31. Refer to §63.7550(b) and (c).

Finally, the above requirements also apply to auxiliary boiler for Unit 6, because it is also deemed a limited-use boiler under the referenced NESHAP.

8.0 Facility Wide Air Toxics

The facility has previously obtained a toxics air permit for emissions of arsenic, beryllium, cadmium, chromium (vi), manganese, mercury and nickel, from various coal storage and handling and ash storage and handling sources. The approved emissions limits are included in Section 2.2 D.1. of the air permit. No changes to the existing requirement are required due to any changes/modifications discussed in this document.

9.0 Facility Emissions Review

Neither the renewal application nor the applications consolidated into the renewal are expected to change the Title V status of the facility. The actual emissions for the facility for 2012-2016 are included on the first page of this application review.

10.0 Other CAA Issues

The Permittee (defendant) has executed a consent decree with (i) the USA (plaintiff) through the Executive Branch's Department of Justice and (ii) Environmental Defense, North Carolina Sierra Club and North Carolina Public Interest Research Group (collectively Plaintiff-Intervenors), on October 20, 2015. Refer to Civil Action No.: 1:00 cv 1262, in the United States of District Court for the Middle District of North Carolina.[21].

This decree includes various requirements for the defendant to comply. With respect to DEC's Cliffside Steam Station, the decree requires the defendant to comply with the requirements pertaining to "Surrender of SO_2 and NOx Allowances"[22] for Cliffside Units 1 through 4[23]. The above requirements are "applicable requirements" per the decree and need to be included in the Title V permit. However, the decree is incorrectly executed with respect to whom the allowances for these pollutants are to be surrendered. Specifically, it states that the EPA is to receive all allowances through a third-party transfer.[24] However, as per the Clean Smokestacks Act (CSA)[25], the Governor of NC has entered into the agreement with the Permittee to transfer to the "State any emissions allowances acquired or that may be acquired by the investor-owned public utility pursuant to 42 U.S.C. §§ 7651-7651o, as implemented by 40 Code of Federal Regulations §§ 73.1 through 73.90 (1 July 2001 Edition); 42 U.S.C. 7410(a)(2)(D)(i)(I), as implemented by 40 Code of Federal Regulations § 51.121 (1 July 2001 Edition), related federal regulations, and the associated State Implementation Plan; 42 U.S.C. § 7426, as implemented by 40 Code of Federal Regulations § 52.34 (1 July 2001 Edition) and related federal regulations; or any similar program established under federal law". In addition, "the State Treasurer shall hold all emissions allowances that are transferred to the State as provided in this subsection in trust for the people of this State and shall sell, trade, transfer, or otherwise dispose of the emissions allowances only as the General Assembly shall provide by law."[26]

In summary, since the terms of the consent decree are contrary to the requirements of CSA, it would be inappropriate to include any allowance surrender requirements of the decree into the renewed title V permit. Finally, it should be noted that the decree requirements are independently enforced against the defendant by the plaintiffs, regardless of whether they have become part of the Title V permit or not.

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[21] Available at https://www.epa.gov/enforcement/consent-decree-duke-energy-corporation-civil-action-no-100-cv-1262.
[22] Id. at 20, Page 40.
[23] Id. at 20, Page 15.
[24] Id. at 20, Page 16.
[25] NCGS §143-215.107(D)(i).
[26] Id. at 24.

11.0 Public Notice/EPA and Affected State(s) Review

Pursuant to 15A NCAC 02Q .0521, a notice of the DRAFT Title V Permit will be placed on NCDEQ website on **xx**. The notice will provide for a 30-day comment period with an opportunity for a public hearing. Copies of the public notice will be sent to persons on the Title V mailing list and EPA on **xx**. Pursuant to 15A NCAC 02Q .0522, a copy of the permit application and the proposed permit (in this case, the draft permit) will be provided to EPA for their 45-day review on **xx**. Also pursuant to 02Q .0522, a notice of the DRAFT Title V Permit will be provided to each affected State at or before the time notice provided to the public under 02Q .0521 above. A copy of the final permit will also be provided to the EPA upon issuance as per 02Q .0522.

12.0 Stipulation Review

The following changes were made to the Duke Energy Carolinas, LLC - Cliffside Steam Station's Air Quality Permit No. 04044T42:

Old Page No. Air Quality Permit No. 04044T42	**New Page No.** Air Quality Permit No. 04044T43	**Condition Number**	**Changes**
Attachment to Cover Letter	Attachment to Cover Letter	Insignificant activity List	Added one 55 kW propane fired emergency generator with an ID number I-148.
3	3	Section 1 Table	Renamed auxiliary boilers for Units 5 and 6 as ES-AuxBU5 and ES-AuxBU6, respectively. Identified ES-AuxBU5 for applicability of 5D NESHAP. Added a footnote for Units 5 and 6 boilers for burning of incidental spills of oil, antifreeze, etc. that might get on the coal from mobile equipment. Added a footnote for biodiesel burning for ES-12, QP5, FWP5, EG6, and FWP. Added a footnote for intermittent use of NOx control devices to comply with the applicable requirements for Unit 6 boiler.
9	9	Section 2.1.A. Table	Removed applicability of CAIR and replaced it with CSAPR for both SO_2 and NOx. Replaced regulatory citation "02D .0501(e)" with "02D .0501(c).
10	10	Section 2.1 A.1.	Replaced regulatory citation "02D .0501(e)" with "02D .0501(c) throughout the stipulation.
10	11	Section 2.1.A.1.f.	Include the following statement: "All instances of deviations from the requirements of this permit must be clearly identified."
12	11	Section 2.1.A.2.c.	Removed the limits established for monitoring purposes as they are not part of the regulation and they are redundant.
12	12	Section 2.1.A.2.d. Section 2.1.A.2.f.	Included a non-compliance statement. Included the following statement: "All instances of deviations from the requirements of this permit must be clearly identified."
16	13	Section 2.1.A.6.	Renumbered it to Section 2.1.A.4.
14	13	Section 2.1.A.4.	Renumbered it to Section 2.1.A.5.
15	14	Section 2.1.A.5.	Renumbered it to Section 2.1.A.6.

Old Page No. Air Quality Permit No. 04044T42	**New Page No.** Air Quality Permit No. 04044T43	**Condition Number**	**Changes**
18	17	Section 2.1.A.7.d.iii.	Removed the monitor downtime definition in the context of monitor bypass. The Unit 5 does not use any bypass stack to release emissions to the atmosphere. So, the requirement does not apply to this unit.
19	18	Section 2.1 A.8.c. Table	Removed the incorrect provision for exempting start-ups, shutdown, off-line activities, malfunction, and maintenance from defining excursions. The CAM regulation does not allow such exemption. See §64.7(c). The CAM only exempts data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities. This permit stipulation will be corrected as stated above.
20	19	Section 2.1.B.	Renamed the Unit 5 auxiliary boiler as ES-AuxBU5.
20	19	Section 2.1.B. Table	Included applicability of 5D NESHAP.
24	22	Section 2.1.C.1.d.	Included a non-compliance statement.
24	22	Section 2.1.C.2.c.	Removed a requirement to establish "normal" for visible emissions for each source listed in Section 2.1.C., as the Permittee had earlier established normal level of visible emissions for the equipment.
25 and 26	23 and 24	Section 2.1.D.	Included a permission to burn diesel in addition to No. 2 fuel oil for emergency/blackout generator ES-12.
25	23	Section 2.1.D. Table Section 2.1.D.1.	Specified for RICE NESHAP that no requirement remained to be complied with for source ES-12. The notification was submitted in 2005. The permittee has also complied with the 5-year record keeping requirement for the applicability determination. Thus, the requirements in Section 2.1.D.3. has been removed.
28	25	Section 2.1.E.2.c.	Removed a requirement to establish "normal" for visible emissions for each source listed in Section 2.1.E., as the Permittee had previously established normal level of visible emissions for the equipment.
29 through 31	26 and 27	Section 2.1.E.3.	Included a non-compliance statement for each testing, monitoring, and recordkeeping requirement.
-	27	Section 2.1.E.3.l.	Included a semi-annual reporting requirement.
32 33	29 30	Section 2.1.F.2.c. Section 2.1.F.3.h.	Removed a requirement to establish "normal" for visible emissions for source LS-1, as the Permittee had established its normal level of visible emissions. Removed a requirement to establish "normal" for visible emissions for each affected source under NSPS, as listed in Section 2.1.F, as the Permittee had established normal level of visible emissions for the equipment.
35	31	Section 2.1.G.1.c.	Removed a requirement to establish "normal" for visible emissions for sources GS-3, GS-4, and GS-9, as the Permittee had previously established normal level of visible emissions for these sources.

Old Page No. Air Quality Permit No. 04044T42	**New Page No.** Air Quality Permit No. 04044T43	**Condition Number**	**Changes**
36	32	Section 2.1.H. Table	Included regulated pollutants under NSPS Subpart IIII.
36	79	Section 2.1.H.2.	Relocated the NSPS IIII requirements for emergency quench water pump QP5 in Section 2.2.F.1.
39	79	Section 2.1.I.2.	Relocated the NSPS IIII requirements for firewater pump FWP5 in Section 2.2.F.1.
41	33	Section 2.1.J. Table	Removed applicability of CAIR and replaced it with CSAPR for both SO_2 and NOx.
42 through 45	35 through 39	Section 2.1.J.1.	Renumbered it to Section 2.1.J.2. Included in Section 2.1.J.2.f. the COMS requirements in accordance with the Procedure 3 "Quality Assurance Requirements for Continuous Opacity Monitoring Systems at Stationary Sources" to Appendix F "Quality Assurance Procedures", in addition to Appendix B "Performance Specifications", under 40 CFR 60, and consistent with NSPS Da. Included a non-compliance statement for each monitoring and recordkeeping requirement. Updated the stipulation to conform the current NSPS Da requirements.
48	34	Section 2.1.J.4.	Renumbered it to Section 2.1.J.1.
45 through 47	39 and 40	Section 2.1.J.2.	Renumbered it to Section 2.1.J.3. Included a deadline to perform the required annual stack tests to no more than 13 months from the previous annual test in Section 2.1.J.3.c. Included pollutant lead in Section 2.1.J.3.j.
51 through 53	40 through 43	Section 2.1.J.8.	Renumbered it to Section 2.1.J.4.
47	44	Section 2.1.J.3.	Renumbered it to Section 2.1.J.6.
49	44	Section 2.1.J.7.	Included a deadline to perform the required annual stack tests to no more than 13 months from the previous annual test in Section 2.1.J.7.c. Removed coal sampling and analysis requirement in Section 2.1.J.7.g. and the reporting requirement in Section 2.1.J.7.h. (as discussed in Section 6.0 of the application review).
53	45	Section 2.1.K.	Renamed the Unit 6 auxiliary boiler as ES-AuxBU6.
57	46	Section 2.1.K.5.	Renumbered it to Section 2.1.K.1. Replaced regulatory citation "02D .0501(e)" with "02D .0501(c).
56	46	Section 2.1.K.1.	Renumbered it to Section 2.1.K.4. Included a non-compliance statement for each monitoring and recordkeeping requirement.

Old Page No. Air Quality Permit No. 04044T42	**New Page No.** Air Quality Permit No. 04044T43	**Condition Number**	**Changes**
			Updated the stipulation to conform the current NSPS Db requirements.
60 through 63	50 through 52	Section 2.1.M.	Included a permission to burn diesel in addition to No. 2 fuel oil for the emergency generator ES-EG6 and fire water pump ES-FWP.
60	50	Section 2.1.M. Table Section 2.1 M.1.	Removed applicability of 02D .0516 as the emergency generator ES-EG6 and fire water pump ES-FWP are subject to sulfur content (15 ppm) requirement under NSPS IIII. So, they cannot be subject to 02D .0516 SO_2 standard. Removed notifications requirement under RICE NESHAP in Section 2.1.M. Table for source EG6 as it had been completed.
61	79	Section 2.1.M.3.	Relocated the NSPS IIII requirements for the emergency generator ES-EG6 and fire water pump ES-FWP in Section 2.2.F.1.
65 and 66	53 and 54	Section 2.1.N.2.d. and e.	Included a non-compliance statement for each testing, monitoring and recordkeeping requirement.
68	56	Section 2.1.O.2.c.	Removed a requirement to establish “normal” for visible emissions for all sources listed in Section 2.1.O., as the Permittee had previously established the normal level of visible emissions for these sources.
69 71	57 64	Section 2.1.P. Table Section 2.1.P.2.	Relocated requirements of 02D .0540 in Section 2.2.B.1.
73	59	Section 2.1.R.2.c.	Removed a requirement to establish “normal” for visible emissions for all sources listed in Section 2.1.R., as the Permittee had previously established normal level of visible emissions for these sources.
88	74	Section 2.2.C.3.c.ii.	Included a deadline to perform the required annual stack tests to no more than 13 months from the previous annual test.
-	76 through 79	Section 2.2.E.1.	Included a MACT DDDDD requirement for both Units 5 and 6 auxiliary boilers.
-	79 through 82	Section 2.2.F.1.	Included an NSPS IIII requirements for QW5, FWP5, EG6, and FWP.
94 and 95	85 and 86	Section 2.5	Revised and renewed the Acid Rain portion of permit (as discussed in Section 6.0 of the application review).
96 and 97	-	Section 2.6	Removed the vacated CAIR requirements.
98 through 106	87 through 95	Section 3	Updated the General Conditions as per the DAQ’s latest TV permit shell.

13.0 Conclusions, Comments, and Recommendations

- The applications discussed in this review do not involve any new control device or any modification to an existing control device. Thus, professional engineer seal requirement in 02Q .0112 does not apply.

- The applications discussed in this review do not involve a new facility or an expansion of an existing facility. Therefore, a consistency determination per 02Q .0507(d)(1) do not apply.

- The pre-public notice version of the draft permit was emailed to DEC on October 29, 2018 for review. Dan Markley of DEC emailed the following comments on November 12, 2018. Additional comments, which are also included below, were sent by DEC on November 15, 2018 via email. The DAQ response to each comment is included below as well:

  Comment 1:

  "New permit page 46, Sections 2.1.K.3.a and c. Both sentences should include firing with No. 2 fuel oil."

  DAQ Response:

  For auxiliary boiler ES-AuxBU6, sulfur dioxide emissions when burning fuel oil, are subject a limit of 0.05 weight percent sulfur in fuel, in accordance with 02D .0501(c) (Section 2.1.K.1.) For the same source, sulfur dioxide emissions when burning propane are subject to an emission limit of 2.3 lb/million Btu, in accordance with 02D .0516 (Section 2.1.K.3.) These are different requirements for each of these permitted fuels for the auxiliary boiler. These requirements are accurate, and no changes are required either for Section 2.1.K.1 or Section 2.1. K.3.

  Comment 2:

  "New permit page 23, Section 2.1.D Table footnote 1. Wording is not clear. This same wording occurs on page 51, Section 2.1.M Table footnote 3."

  DAQ Response:

  The Permittee was required pursuant to the current permit to submit an initial notification under MACT Subpart ZZZZ and keep records for the applicability determination for five years. The Permittee had satisfied both requirements: submitted the initial notification to the DAQ in 2005 and kept the record of applicability determination for more than five years at the facility. Therefore, no requirements were remained to comply with. The referenced footnote will be clarified to exclude the redundant word "with".

  Comment 3:

  "New permit page 18, Section 2.1.A.8.c (CAM). Startup, shutdown, and the other exclusions were taken out. Although we have no intentions to revert to using COMS for PM compliance, we want to make sure the permit language is appropriate. The purpose of this CAM is to assure the particulate control devices are working properly. Having an excursion because of one of the listed excluded periods may not be an indication of control device problems, but nonetheless would require an inspection and corrective actions. We still have the obligation to operate and maintain the source in accordance with good air pollution control practices for minimizing emissions during such periods. Malfunctions are treated separately and have their own response requirements. We believe the exclusions should remain in the permit."

  DAQ Response:

  The current permit in Section 2.1.A.8.c. exempts opacity data, recorded using COMS, during startup, shutdown, off-line activities, malfunction, and maintenance, for determining whether a stack test is required to be performed for demonstrating compliance with the PM standard. But, no such exemptions are available for data recorded during SSM events. However, CAM regulation in §64.7(c) does provide some scenarios, as below, where the data can be excused:

  > "Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part."

  Therefore, the draft permit was revised to replace the exceptions for data recorded during the SSM events with the data exceptions as included in §64.7(c).

It should also be noted that the above same comment was made by Sierra Club (December 15, 2017) on the proposed permit 03757T43 for a similar coal-fired facility owned by Duke Energy for its Allen Steam Station. This environmental group argued that the CAM regulation did not excuse data recorded during the SSM events for the purposes of CAM, which the DAQ agreed. Thus, for this Duke Energy Allen Steam Station permit, DAQ had replaced the SSM data exemption to the exceptions as provided in §64.7(c), as discussed above.

In summary, no changes to the draft permit will be made for the above DEC comment on Cliffside Steam Station.

Comment 4:

The Permittee has provided changes to the permit shield for non-applicable requirements, with respect to various sources, as included in Section 2.4 of the current permit. The changes are as below (strike-outs and additions). Note that the DEC has provided explanations for such changes.

A. The following requirements are not applicable to boiler ID No. ES-5; nor auxiliary boiler ~~ES-6(AuxB)~~ES-AuxBU5:

1. 15A NCAC 02D .2618, testing for mercury emissions, is not applicable because 15A NCAC 02D .0537, "Control of Mercury Emissions", does not apply to fuel combustion.

~~2. 15A NCAC 02D .2602, testing for sources for which emissions are based on process rates, is not applicable because emissions for these sources are not based on process rates.~~ Remove. Citation is valid for other testing.

3. 15A NCAC 02D .0607, calibration and maintenance requirements do not apply as these sources do not combust wood and wood-fossil fuels.

4. 15A NCAC 02D .1110, NESHAP promulgated in 40 CFR Part 61, is not applicable because no NESHAP evaluation has been triggered.

5. 15A NCAC 02D .0902~~(e)~~(f), applicability of VOC rules to sources in non-attainment areas, is not applicable because there are no rules applicable to these sources in 02D .0900. Rutherford County is not listed and therefore not subject to this rule (facility located in an attainment area). Section 182(b)(2) of the Clean Air Act also pertains to facilities in non-attainment areas. Given this exclusion and the one below none of the rules in 02D .0900 apply.

6. 15A NCAC 02D .0902~~(f)~~(e), exemptions from VOC rules in 15A NCAC 02D .0900, is not applicable because there are no rules applicable to these sources in 02D .0900. Sources not listed.

~~7. 15A NCAC 02D .0903(b), recordkeeping on VOC emissions and control equipment, is not applicable because there are no rules applicable to these sources in 02D .0900.~~

~~8. 15A NCAC 02D .0903(d)(2), recordkeeping on VOC source compliance, is not applicable because there are no rules applicable to these sources in 02D .0900.~~

~~9. 15A NCAC 02D .0903(e), recordkeeping on VOC's, is not applicable because there are not rules applicable to these sources in 02D .0900.~~

~~11. 15A NCAC 02D .0912 is not applicable because there are no rules applicable to these sources in 02D .0900.~~

~~13. 15A NCAC 02D .0939(a), testing for VOC's for sources subject to 02D .0912, is not applicable because there are no rules applicable to these sources in 02D .0900.~~

~~14. 15A NCAC 02D .0939(b), testing for VOC's for sources subject to 02D .0912, is not applicable because there are no rules applicable to these sources in 02D .0900.~~

15. 15A NCAC 02D .1402~~0~~, NOX requirements for non-attainment counties, is not applicable because Rutherford County is not a~~n~~ non-attainment area. Corrected reference.

~~16. 15A NCAC 02Q .0508(p)(1), recordkeeping on alternative operating scenarios, is not applicable because there are no alternative operating scenarios.~~ No longer needed. Reference to alternative operating scenario in rule was removed.

B. The following requirements are not applicable to boiler ID No. ES-5:

1. 15A NCAC 02D .0503~~(a)~~(c), particulates from fuel burning indirect heat exchangers, is not applicable since the boilers are covered under 15A NCAC 02D .0536 for particulate emissions. Corrected reference.

C. The following requirements are not applicable to auxiliary boiler ID No. ~~ES-6(AuxB)~~ES-AuxBU5:

1. 15A NCAC 02D .2612, compliance testing for nitrogen oxides, is not applicable because there are no nitrogen oxide requirements applicable to these sources.

D. The following requirements are not applicable to auxiliary boiler ID No. ES-AuxBU5 nor ES-AuxBU6: These exemptions also apply to ES-AuxBU6.

1. 15A NCAC 02D .2609(c), particulate testing for steam generators which utilize soot blowing shall determine the contribution of soot blowing, is not applicable to these sources because these sources do not utilize soot blowing. Corrected reference. Changed numbering here and subsequent references.

2. 15A NCAC 02D .0519, nitrogen oxide emission limits, is not applicable because the auxiliary boilers have a heat input rating of less than 250 million Btu per hour each.

3. 15A NCAC 02D .0535(d) and (e), malfunction abatement plan requirements and submittal, is not applicable because the plan is only required for electric utility boilers.

4. 15A NCAC 02D .0536, emission limits for particulate matter from utility boilers, is not applicable because these sources are not utility boilers.

5. 15A NCAC 02D .0606, monitoring of fossil-fired steam generators in accordance with Appendix P of 40 CFR Part 51, is not applicable because the auxiliary boilers have a heat input rating of less than 250 million Btu per hour each.

6. 15A NCAC 02D .0608, sulfur dioxide emissions from other coal or residual oil burners, is not applicable because these sources do not burn coal or residual oil.

7. 15A NCAC 02Q .0401, implementation of Phase II of the federal acid rain program pursuant to the requirements of Title IV of the Clean Air Act as provided in 40 CFR Part 72, is not applicable because these sources are not utility units.

DE. The following requirement is not applicable to boiler ES-6:

1. Emissions of sulfur dioxide, nitrogen oxides and filterable particulate matter/PM-10 are exempt from Compliance Assurance Monitoring in accordance with 40 CFR 64.2(b)(vi) since the permit specifies a continuous compliance determination method for meeting the applicable emission limits.

DAQ Response:

The DAQ agrees with the explanations provided by DEC with respect to various changes to the permit shield requirements in Section 2.4. Therefore, the requested changes will be implemented.

Comment 5:

"New permit page 35, Section 2.1.J.2.b and d. Sulfur dioxide is included in the footnote in the table, but not included in the sentence in d. Sentence should also reference Section 60.43 as applicable for SO2."

DAQ Response:

Agreed. The DAQ will include an exemption from compliance with the SO_2 standard during the SSM events in Section 2.1.J.2.d. as allowed in §60.48Da(a).

Comment 6:

"New permit page 72, Section 2.2.C.2.vv. Electronic reporting requirements for 40 CFR 63. Currently we use ECMPS for all of our MATS reporting (Section nn). The method stated in the permit Section vv cannot currently be used and the July 1, 2018 has passed for having the software available. Just waiting on EPA to fix this. My suggestion, remove the fixed date and start the sentence with "Within 60 days after…". Then add a statement after the methodology "when the software becomes available". This is a little out of my area, but apparently PDF files can be uploaded (through ECMPS) but not data directly to the WebFire database."

DAQ Response:

Section 2.2.C.2.vv. of the permit includes the requirement as provided in §63.10031 (f). The DAQ agrees that the language as written in the regulation may not be appropriate now, in addition, it is possible that the EPA may not be ready with this electronic system. But, the DAQ is not in a position to rewrite the permit stipulation contrary to the regulation.

- The draft permit was emailed to the regional office on October 29, 2018 for review.
- This permit engineer recommends issuing the renewed / revised permit after the completion of both public comment and EPA review periods.

Appendix A

Application Review for Air Quality Permit No. 04044T39
(Issuance date May 9, 2014)

NORTH CAROLINA DIVISION OF AIR QUALITY

Air Permit Review

Permit Issue Date: 05/09/2014

Region: Asheville Regional Office
County: Rutherford
NC Facility ID: 8100028
Inspector's Name: Mike Parkin
Date of Last Inspection: 09/06/2013
Compliance Code: 3 / Compliance - inspection

Facility Data

Applicant (Facility's Name): Duke Energy Carolinas, LLC - Cliffside Steam Station

Facility Address:
Duke Energy Carolinas, LLC - Cliffside Steam Station
573 Duke Power Road (SR 1002)
Cliffside, NC 28024

SIC: 4911 / Electric Services
NAICS: 221112 / Fossil Fuel Electric Power Generation

Facility Classification: Before: Title V **After:** Title V
Fee Classification: Before: Title V **After:** Title V

Permit Applicability (this application only)

SIP: 2D .0524
NSPS: Subpart Y
NESHAP:
PSD:
PSD Avoidance:
NC Toxics:
112(r):
Other:

Contact Data

Facility Contact	Authorized Contact	Technical Contact
Steve Hodges Environmental Coordinator (828) 657-2339 573 Duke Power Road Mooresboro, NC 28114	Rick Roper Manager Cliffside Steam Station (828) 667-2001 573 Duke Power Road Mooresboro, NC 28114	William Horton Senior Environmental Specialist (980) 373-3226 526 South Church Street (EC13K) Charlotte, NC 28202

Application Data

Application Number: 8100028.13E
Date Received: 09/03/2013
Application Type: Modification
Application Schedule: TV-Sign-501(c)(2)

Existing Permit Data

Existing Permit Number: 04044/T38
Existing Permit Issue Date: 10/14/2013
Existing Permit Expiration Date: 05/31/2015

Total Actual emissions in TONS/YEAR:

CY	SO2	NOX	VOC	CO	PM10	Total HAP	Largest HAP
2012	316.21	458.51	15.51	309.05	203.55	18.67	14.81 [Hydrogen chloride (hydrochlori]
2011	310.05	712.01	32.19	631.70	545.97	42.93	35.61 [Hydrogen chloride (hydrochlori]
2010	12219.62	864.72	31.50	610.46	771.29	881.90	821.95 [Hydrogen chloride (hydrochlori]
2009	22985.27	1050.62	40.21	785.06	1222.81	1637.03	1527.42 [Hydrogen chloride (hydrochlori]
2008	29424.63	2308.01	64.70	1141.22	1530.87	1996.09	1837.60 [Hydrogen chloride (hydrochlori]

Review Engineer: Ed Martin **Review Engineer's Signature:** **Date:** 05/09/2014	**Comments / Recommendations:** **Issue** 04044/T39 **Permit Issue Date:** 05/09/2014 **Permit Expiration Date:** 05/31/2015

I. Purpose of Application

The purpose of this application is to add to the permit three new coal handling sources and an expanded coal pile for which Duke submitted a Notice of Intent to Construct and for which approval for construction was given in DAQ's letter dated August 23, 2013. Two new coal handling sources are part of the Unit 6 coal blending system: an underground Unit 6 coal blend reclaim hopper (ES-C20) and a Unit 6 coal blend reclaim conveyor (ES-C31) which is partially underground. The reclaim hopper ES-C20 takes coal from the coal pile and transfers coal to conveyor ES-C31 which then goes to another existing conveyor. Also, an underground Unit 5 coal blend reclaim hopper (C-21) is being installed but will be capped for later use and is not operable at this time. The coal pile will be expanded by 1.1 acres resulting in an increase from 16.9 acres to 18 acres.

This permit modification is being processed as a two-step significant modification under 15A NCAC 2Q .0501(c)(2). Therefore, public notice is not required at this time.

II. Permit Changes

The following changes were made to the Duke Energy Carolinas LLC Cliffside Air Permit No. 04044T38:

Page	Section	Description of Changes
cover	--	Amended permit numbers and dates.
4-7	Section 1, table of permitted emission sources	Added sources C-21, ES-C20 and ES-C31.
		Changed size of C-9 and C-10 coal pile from 16.9 acres to 18 acres.
23	Section 2.1.E, equipment description	Added Unit 5 coal blend reclaim hopper (ID No. C-21).
23	Section 2.1.E, table of applicable regulations	Added C-21 for Subpart Y visible emissions.
25	Section 2.1.E.3.c	Added C-21.
26	Section 2.1.E.3.e	Added C-21 with footnote 1.
39-41	Section 2.1.J.1	Corrected all NSPS Subpart Da references in this section to add "D" to the paragraph numbers (example from §60.44a to §60.44Da).
39	Section 2.1.J.1.f	Changed reference to Appendix F "Quality Assurance Procedures" to 15A NCAC 2D .0613 "Quality Assurance Program."
62	Section 2.1.N, equipment description	Added Unit 6 Coal Blend Reclaim Hopper (ID No. ES-C20) and Unit 6 Coal Blend Reclaim Conveyor (ID No. ES-C31).
62	Section 2.1.N, table of applicable regulations	Added ES-C20 and ES-C31 for Subpart Y visible emissions.
63	Section 2.1.N.2.c	Added ES-C20 and ES-C31.

Page	Section	Description of Changes
63	Section 2.1.N.2.e	Added ES-C20 and ES-C31 with footnote 2.

III. Facility Description

Duke Energy's Cliffside Steam Station is an electric power generating facility with emission sources consisting of five coal/No. 2 fuel oil-fired electric utility boilers (ID Nos. ES-1, ES-2, ES-3, ES-4 and ES-5); two No. 2 fuel oil/propane-fired auxiliary boilers; and various ancillary equipment including flyash, coal, limestone, and ash handling equipment. A new 800 MW coal-fired boiler (Unit 6), permitted in January 29, 2008, commenced commercial operation in December, 2012. Retired Units 1-4 (ID Nos. ES-1, ES-2, ES-3 and ES-4) and the associated auxiliary boiler ES-7(AuxB) were recently removed from the permit in revision T38.

IV. Summary of Changes to Emission Sources or Control Devices

The equipment description changes to add the alkaline-based fuel additives are as follows (changes in **bold**):

Emission Source ID No.	Emission Source Description	Control Device ID No.	Control Device Description
C-9 and C-10 NSPS PSD	Coal storage pile fugitive emissions (**maximum 18 acres**)	None	N/A
C-21 NSPS	**Unit 5 coal blend reclaim hopper (750 tons per hour maximum capacity) underground**	**None**	**N/A**
ES-C20 NSPS	**Unit 6 Coal Blend Reclaim Hopper (750 tons per hour maximum capacity) underground**	**N/A**	**N/A**
ES-C31 NSPS	**Unit 6 Coal Blend Reclaim Conveyor (36 inches wide x 333 feet long, 750 tons per hour maximum capacity)**	**N/A**	**N/A**

V. Emission and Regulatory Evaluation

A. <u>NSPS Subpart Y Requirements (permit sections 2.1.E and 2.1.N)</u>
The following requirements are applicable:

<u>Visible Emissions</u>
The Unit 5 coal blend reclaim hopper (C-21), Unit 6 coal blend reclaim hopper (ES-C20), and Unit 6 coal blend reclaim conveyor (ES-C31) are subject to a visible emissions standard of 10% opacity (except during start-up, shutdown and malfunction) for coal processing and conveying equipment constructed, reconstructed, or modified after April 28, 2008 in accordance with §60.254(b)(1). However, the Unit 5 coal blend reclaim hopper (C-21) is capped for a potential future Unit 5 blending project and is inoperable at this time. The permit requires (footnote 1) the Permittee to submit an application to modify the permit if and when hopper C-21 is to become operable in order to establish the testing/monitoring requirements. The testing/monitoring point for C-21will not be known until such time that a transport conveyor for Unit 5 is installed (and the actual configuration is determined) which will take coal from this hopper (similar to

what is now being installed on Unit 6 with hopper ES-C20 and conveyor ES-C31). Therefore, the following applies only to ES-C20 and ES-C31 at this time:

Testing/Monitoring

1. The sources (item 1 above) subject to an opacity standard must conduct an initial performance test and thereafter, a new performance test must be conducted according to the schedule in §60.255(b)(2).

Recordkeeping/Reporting

1. The following is required to be maintained in a logbook (written or electronic) on-site and made available upon request as specified in §60.258. The logbook shall record the following as applicable:
   a. The manufacturer's recommended maintenance procedures and the date and time of any maintenance and inspection activities and the results of those activities. Any variance from manufacturer's recommendations shall be noted.
   b. The date and time of periodic coal preparation and processing plant visual observations, noting those sources with visible emissions along with corrective actions taken to reduce visible emissions. Results from the actions shall be noted.
   c. The amount and type of coal processed each calendar month.
   d. The amount of chemical stabilizer or water purchased for use in the coal preparation and processing plant.
   e. Monthly certification that the dust suppressant systems were available for operation as needed to control fugitive emissions when any coal was processed, and that manufacturer's recommendations were followed for all control systems. Any variance from the manufacturer's recommendations shall be noted.
   f. Monthly certification that the Open Coal Storage Facility Fugitive Dust Control Plan was implemented as described. Any variance from the plan shall be noted. A copy of the Open Coal Storage Facility Fugitive Dust Control Plan and any letters from the DAQ providing approval of any alternative control measures shall be maintained with the logbook. Any actions, *e.g.* objections, to the plan and any actions relative to the alternative control measures, *e.g.* approvals, shall be noted in the logbook as well.
2. For the purpose of reports required under §60.7(c), the Permittee must report semiannually periods of excess emissions of all 6-minute average opacities that exceed the applicable standard as specified in §60.258.
3. The Permittee must submit the results of all performance tests consistent with the provisions of section §60.8 as specified in §60.258.
4. Within 60 days after the date of completing each performance evaluation conducted to demonstrate compliance, the Permittee shall submit the test data to EPA by successfully entering the data electronically into EPA's WebFIRE data base as specified in §60.258.

Open Coal Storage Pile

The coal storage pile (C-9 and C-10) is being expanded by 1.1 acres. The coal pile is subject to a requirement that open coal storage piles, which includes the equipment used in the loading, unloading, and conveying operations of the affected facility; constructed, reconstructed, or modified after May 27, 2009, must operate in accordance with a submitted fugitive coal dust emissions control plan that is appropriate for the site conditions in order to minimize fugitive coal dust emissions in accordance with §60.254(c). Duke has submitted with this application Revision 1 to their Open Coal Storage Facility Fugitive Dust Control Plan for the Cliffside Steam Station dated April 2014 as sent by email to Ed Martin from Bill Horton on April 21, 2014, with a letter signed by the RO dated April 13, 2014. The plan was revised to include the expanded coal pile. As required by §60.254(c), the plan identifies and describes the control measures used to minimize fugitive coal dust emissions and explains how the measures are applicable and appropriate for the site conditions. The plan was determined to be acceptable and applies to the coal pile (C-9 and C-10) and sources C-7 and C-11. The sources subject to the open storage pile requirements must operate in accordance with the most recent revision of the Open Coal Storage Facility Fugitive Dust Control Plan as required by §60.254(c). The control measures under the PSD requirements in Part B, Section 2.2.A.1 of the permit for these sources are used to minimize to the greatest extent practicable fugitive coal dust emissions. The plan must be revised as needed to reflect any changing conditions that may affect fugitive coal dust emissions at the source. Such revisions must be dated and submitted to the DAQ before a source can operate pursuant to the revisions. Any chemical dust suppression agent as a control measure to minimize fugitive coal dust emissions must be implemented in accordance with §60.254(c)(6) and included in the plan. Currently Duke does not use any chemical dust suppressants.

B. Emissions Increases

The following are the fugitive emissions increases for which calculations on Form D6 were included with the application, with corrections as emailed from Bill Horton to Ed Martin on April 24, 2014 using the latest version of AP-42 which changed the k factor for $PM_{2.5}$ used in the calculations in 2 below from 0.11 as used in the original application to 0.053:

1. Unit 5 coal blend reclaim hopper (C-21) and Unit 6 coal blend reclaim hopper (ES-C20)

   These hoppers are underground; therefore, no fugitive emissions are expected. In addition, the Unit 5 coal blend reclaim hopper (C-21) is capped and is inoperable at this time. Even though no emissions are expected from the Unit 6 coal blend reclaim hopper (ES-C20), it is subject to VE monitoring. The reclaim hopper ES-C20 takes coal from the coal pile and transfers coal to conveyor ES-C31 at a point underground in a tunnel and the conveyor is covered aboveground. The VE test point for ES-C20 is where the conveyor ES-C31/tunnel structure comes aboveground at which point there is a vent fan that is used for safe ventilation of the tunnel and no emissions are expected from ES-C20.

   Note, Duke was asked whether ES-C20 would be considered a *mechanical vent* under Subpart Y since 60.251 defines it to mean "any vent that uses a powered mechanical drive (machine) to induce air flow." A mechanical vent would have a PM concentration limit in addition to a VE limit. Duke responded that they had asked EPA (letter dated January 9, 2012) when Unit 6 was undergoing initial NSPS testing whether the same arrangement with a vent fan for hopper C-19, originally installed for Unit 6, would be subject to a PM concentration limit. EPA responded in a determination letter to Sheila Holman that they intended for the PM concentration limit to apply to mechanical vents that are attached to affected facilities and that the limit is not required for mechanical vents used for general ventilation on buildings (e.g. tunnel structure).

2. Unit 6 coal blend reclaim conveyor (ES-C31)

   At the Unit 6 heat input of 7850 mmBtu/hr and coal heat content of 9376 Btu/lb, the maximum coal use (used to determine the maximum annual emission rates) is:

   (7850 mmBtu/hr)(1 lb/9376 Btu/lb) (8760 hr/yr)/(2000 lb/ton) = 3,667,129 tons/yr

   The C-31 conveyor process rate is 750 tons/hr (used to determine the maximum hourly rates).

   Using equation (1) in AP-42 Section 13.2.4:

   $$E = k(0.0032)\ (((U/5)^{1.3})/((M/2)^{1.4}))$$

   Where: E = emission factor, lb/ton
   k = particle size multiplier = 0.74 for PM
   = 0.35 for PM_{10}
   = 0.053for $PM_{2.5}$
   U = mean wind speed, mph = 7.3 mph*
   M = coal moisture = 4.5%*
   Control efficiency = 75%*

   *Values taken from Cliffside U6 application of May 2007, Appendix B, page 12.

   Therefore, the emission factors are: E = 1.24 E-03 lb/ton for PM
   = 5.89 E-04 lb/ton for PM_{10}
   = 8.88 E-05 lb/ton for $PM_{2.5}$

   Hourly emission rates are:

(conveyor process rate, tons/hr) (emission factor, lb/ton) (100% - control eff %)

(750 tons/hr) (1.24 E-03 lb/ton) (100% - 75%) = **0.233 lb/hr for PM**
(750 tons/hr) (5.89 E-04 lb/ton) (100% - 75%) = **0.110 lb/hr for PM_{10}**
(750 tons/hr) (8.88 E-05 lb/ton) (100% - 75%) = **0.017 lb/hr for $PM_{2.5}$**

And annual emission rates are:

(annual coal use, tons/yr) (emission factor, lb/ton) (100% - control eff %)/2000 lb/ton

(3,667,129 tons/yr) (1.24 E-03 lb/ton) (100-75)/(2000 lb/ton) = **0.568 tons/yr for PM**
(3,667,129 tons/yr) (5.89 E-04 lb/ton) (100-75)/(2000 lb/ton) = **0.270 tons/yr for PM_{10}**
(3,667,129 tons/yr) (8.88 E-05 lb/ton) (100-75)/(2000 lb/ton) = **0.041 tons/yr for $PM_{2.5}$**

3. Expanded Coal Pile
Fugitive emissions increases for the expanded coal pile are based on an increased size of 1.1 acres from 16.9 acres to 18 acres resulting in an increase of:

1.1 acres/16.9 acres = 0.0651 = 6.51% increase in size

Using the original emissions from the Cliffside application of May 2007, Appendix B, page 18, with PM emissions of 3.3 tons/yr and PM_{10} emissions of 1.6 tons/yr, the emissions increase is proportional to the increased pile size as follows:

(3.3 tons/yr) (0.0651) = **0.21 tons/yr for PM**

(1.6 tons/yr) (0.0651) **= 0.10 tons/yr for PM_{10}**

Using AP-42 conversion from PM_{10} to $PM_{2.5}$: k $PM_{2.5}$ /k PM_{10} = 0.11/0.35 = 0.31 factor:

(0.10 tons/yr PM10) (0.31factor) = **0.03 tons/yr for $PM_{2.5}$**

These increases are far below the PSD thresholds and no PM/ PM_{10}/$PM_{2.5}$ limits apply for these fugitive emissions.

VI. Public Notice

These changes are being processed as a two-step significant modification under 15A NCAC 2Q .0501(c)(2). Therefore, public notice is not required at this time.

VII. Other Requirements

PE Seal
Not applicable since no control devices are being added.

Zoning
Duke sent the application to the Cleveland County and Rutherford County planning departments for review. The Cleveland County planning department responded in a letter dated August 27, 2013, that the new equipment will be located in Rutherford County and that the expanded coal pile would not require a zoning permit for that use. The Rutherford County planning department responded in a letter dated August 30, 2013, that they have reviewed the application and that no further action is required for this request.

Fee Classification
The facility fee classification before and after this modification will remain as “Title V”.

VIII. Recommendations

The draft permit was sent to Bill Horton at Duke for review on April 17, 2014. Duke responded (email dated April 28, 2014 from Bill Horton) that they had no further comments other than what was previously addressed and incorporated into the draft permit. The draft permit was sent to Mike Parkin at the Asheville Regional Office on April 25, 2014. ARO had no comments (email dated May 6, 2014 from Mike Parkin).

Issuance is recommended.